GREEN MOUNTAIN POWER CORP
Form 10-Q
November 08, 2006

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, 2006

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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act. (Check One)
Large Accelerated Filer o Accelerated Filer x Non-accelerated filer o

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

The number of shares of Common Stock, $3.33 1/3 par value, outstanding as of October 31, 2006: 5,294,461.

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.

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PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

GREEN MOUNTAIN POWER CORPORATION Consolidated Comparative Income Statements	**Unaudited**			
	Three Months Ended September 30		**Nine Months Ended September 30**	
	2006	**2005**	**2006**	**2005**
Operating revenues	(In thousands)			
Retail Revenues	$ 54,615	$ 57,584	$ 160,242	$ 162,874
Wholesale Revenues	6,818	6,740	21,547	14,586
Total operating revenues	61,433	64,324	181,789	177,460
Operating expenses				
Power Supply				
Vermont Yankee Nuclear Power Corporation	11,184	8,375	31,417	25,837
Company-owned generation	2,752	1,905	5,488	4,336
Purchases from others	22,199	30,125	69,094	77,739
Other operating	8,876	6,968	22,184	17,124
Transmission	2,995	4,077	12,647	12,707
Maintenance	2,664	2,842	7,980	7,871
Depreciation and amortization	3,577	3,770	10,794	11,299
Taxes other than income	1,674	1,530	5,063	4,914
Income taxes	1,460	893	4,842	3,826
Total operating expenses	57,381	60,485	169,509	165,653
Operating income	4,052	3,839	12,280	11,807
Other income				
Equity in earnings of affiliates and non-utility operations	527	360	1,396	1,201
Allowance for equity funds used during construction	32	8	74	22
Other income (deductions), net	134	3	53	(70)
Total other income	693	371	1,523	1,153
Interest charges				
Long-term debt	1,753	1,633	5,020	4,901
Other interest	175	57	424	173
Allowance for borrowed funds used during construction	(14)	(4)	(34)	(14)
Total interest charges	1,914	1,686	5,410	5,060
Income from continuing operations	2,831	2,524	8,393	7,900
Income (Loss) from discontinued operations, net	53	18	129	2
Net income applicable to common stock	$ 2,884	$ 2,542	$ 8,522	$ 7,902

Consolidated Statements of Comprehensive Income	Unaudited							
	Three Months Ended				Nine Months Ended			
	September 30				September 30			
	2006		2005		2006		2005	
	(In thousands, except per share data)							
Net income	$	2,884	$	2,542	$	8,522	$	7,902
Other comprehensive income, net of tax		-		-		-		-
Comprehensive income	$	2,884	$	2,542	$	8,522	$	7,902
Basic earnings per share	$	0.55	$	0.49	$	1.62	$	1.52
Diluted earnings per share	$	0.54	$	0.48	$	1.60	$	1.50
Cash dividends declared per share	$	0.28	$	0.25	$	0.84	$	0.75
Weighted average common shares outstanding-basic		5,280		5,208		5,261		5,185
Weighted average common shares outstanding-diluted		5,362		5,301		5,338		5,284

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

GREEN MOUNTAIN POWER CORPORATION
Consolidated Statements of Cash Flows

	Unaudited For the Nine Months Ended September 30 2006	2005
Operating Activities:	(In thousands)	
Income from continuing operations	$ 8,393	$ 7,900
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	10,794	11,299
Dividends from associated companies	869	916
Equity in undistributed earnings of associated companies	(1,215)	(1,107)
Allowance for funds used during construction	(108)	(36)
Amortization of deferred purchased power costs	1,533	1,841
Deferred income tax expense, net of investment tax credit amortization	183	(1,175)
Deferred purchased power costs	(4,714)	(2,023)
Deferred revenues	3,288	1,284
Environmental and conservation deferrals, net	(738)	(13)
Share-based compensation	1,479	780
Changes in:		
Accounts receivable and accrued utility revenues	(2,514)	(1,390)
Prepayments, fuel and other current assets	(2,717)	686
Accounts payable and other current liabilities	1,061	285
Accrued income taxes payable and receivable	(6,395)	1,012
Other	(1,451)	(1,140)
Net cash provided by continuing operations	7,748	19,119
Operating cash flows from discontinued operations	129	2
Net cash provided by operating activities	7,877	19,121
Investing Activities:		
Construction expenditures	(12,424)	(12,121)
(Restriction)release of cash for renewable energy investments	(177)	(969)
Investment in associated companies	(15,823)	-
Return of capital from associated companies	257	166
Investment in nonutility property	(119)	(156)
Net cash used in investing activities	(28,286)	(13,080)
Financing Activities:		
Payments on capital lease	(63)	-
Issuance of common stock	454	946
Proceeds from long term debt	11,000	-
Short-term debt	8,002	(3,000)
Cash dividends	(4,428)	(3,898)
Net cash used in financing activities	14,965	(5,952)
Net increase in cash and cash equivalents	(5,443)	89
Cash and cash equivalents at beginning of period	6,500	1,720
Cash and cash equivalents at end of period	$ 1,057	$ 1,809

Supplemental Disclosure of Cash Flow Information:				
Cash paid year-to-date for:				
Interest	$	4,602	$	4,362
Income taxes		7,936		3,073
Non-cash construction additions		750		567

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

GREEN MOUNTAIN POWER CORPORATION
Consolidated Balance Sheets

	Unaudited At September 30, 2006	At December 31, 2005
ASSETS	(In thousands)	
Utility plant		
Utility plant, at original cost	$ 355,226	$ 347,947
Less accumulated depreciation	130,727	122,924
Utility plant, net of accumulated depreciation	224,499	225,023
Property under capital lease	4,369	4,369
Construction work in progress	11,331	7,519
Total utility plant, net	240,199	236,911
Other investments		
Associated companies, at equity	26,160	10,036
Other investments	10,611	10,627
Total other investments	36,771	20,663
Current assets		
Cash and cash equivalents	1,057	6,500
Accounts receivable, less allowance for doubtful accounts of $378 and $484	23,393	19,594
Accrued utility revenues	6,006	7,291
Fuel, materials and supplies, average cost	6,486	6,360
Power supply derivative asset	1,994	15,342
Power supply regulatory asset	4,883	7,791
Prepayments and other current assets	4,025	1,434
Income tax receivable	1,849	-
Total current assets	49,693	64,312
Deferred charges		
Demand side management programs	4,741	5,835
Purchased power costs	5,000	1,812
Pine Street Barge Canal	13,344	12,861
Power supply regulatory asset	18,125	22,344
Other regulatory assets	6,180	5,809
Other deferred charges	4,589	3,068
Total deferred charges	51,979	51,729
Non-utility		
Property and equipment	-	246
Other assets	291	407
Total non-utility assets	291	653
Total assets	$ 378,933	$ 374,268

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

GREEN MOUNTAIN POWER CORPORATION
Consolidated Balance Sheets

	Unaudited At September 30, 2006	At December 31, 2005
CAPITALIZATION AND LIABILITIES	(In thousands except share data)	
Capitalization		
Common stock, $3.33 1/3 par value, authorized 10,000,000 shares (issued 6,117,400 and 6,060,962)	$ 20,391	$ 20,203
Additional paid-in capital	82,400	81,271
Retained earnings	39,958	35,864
Accumulated other comprehensive income	(3,263)	(3,263)
Treasury stock, at cost (827,639 shares)	(16,701)	(16,701)
Total common stock equity	122,785	117,374
Long-term debt, less current maturities	90,000	79,000
Total capitalization	212,785	196,374
Capital lease obligation	3,881	3,944
Current liabilities		
Current portion of long term debt	14,000	14,000
Short-term debt	8,002	-
Accounts payable, trade and accrued liabilities	8,966	14,196
Accounts payable to associated companies	6,530	1,483
Accrued taxes	1,058	5,603
Power supply derivative liability	4,883	7,791
Power supply regulatory liability	1,994	15,342
Customer deposits	954	1,052
Interest accrued	1,907	1,137
Other	2,645	2,552
Total current liabilities	50,939	63,156
Deferred credits		
Power supply derivative liability	18,125	22,344
Accumulated deferred income taxes	28,487	28,092
Unamortized investment tax credits	2,068	2,280
Pine Street Barge Canal cleanup liability	5,694	6,096
Accumulated cost of removal	21,475	21,105
Deferred compensation	10,055	8,213
Other regulatory liabilities	10,516	6,513
Other deferred liabilities	12,369	13,777
Total deferred credits	108,789	108,420
COMMITMENTS AND CONTINGENCIES, Note 3		
Non-utility		
Net liabilities of discontinued segment	2,539	2,374
Total non-utility liabilities	2,539	2,374
Total capitalization and liabilities	$ 378,933	$ 374,268

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

Consolidated Statements of Retained Earnings	Unaudited Three Months Ended September 30 2006	2005	Nine Months Ended September 30 2006	2005
	(In thousands)			
Balance - beginning of period	$ 38,555	$ 32,657	$ 35,864	$ 29,889
Net Income	2,884	2,542	8,522	7,902
Cash Dividends-common stock	(1,481)	(1,306)	(4,428)	(3,898)
Balance - end of period	$ 39,958	$ 33,893	$ 39,958	$ 33,893

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

ITEM 1. NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

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 2005 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. 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 or benefits, typically treated as expenses or income by unregulated entities, to be deferred and expensed or benefited in future periods. Costs are deferred as regulatory assets when the Company concludes that future revenue will be provided to permit recovery of the previously incurred cost. Revenues may also be deferred as regulatory liabilities that would be returned to customers by reducing future revenue requirements. The Company analyzes evidence supporting deferral, including provisions for recovery in regulatory orders, past regulatory precedent, other regulatory correspondence and legal representations. Management’s conclusions on the recovery of regulatory assets represent a critical accounting estimate.

Conditions that could give rise to the discontinuance of SFAS 71 include increasing competition that restricts the Company’s ability to recover specific costs, and a change in the manner in which rates are set by regulators from cost-based regulation to some other form of regulation.

Revenues
The VPSB sets the rates we charge our customers for their electricity. 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 class (residential, 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, 2005 (the "Form 10-K"). The Company expects to contribute approximately $3.0 million to its defined benefit plans in 2006. During the nine months ended September 30, 2006, GMP contributed $2.5 million to its defined benefit plans.

For the Three Months Ended September 30, 2006	**Qualified Pension Plan**	**Supplemental Pension Plan**	**Post-Retirement Benefit Plan**	**Total**
		(In thousands)		
Service cost	$ 319	$ 25	$ 81	$ 425
Interest cost	531	75	250	856
Expected return on plan assets	(669)	0	(250)	(919)
Amortization of the transition obligation	0	0	81	81
Amortization of prior service cost	31	19	(62)	(12)
Recognized net actuarial gain	100	12	63	175
Net periodic pension benefit cost	$ 312	$ 131	$ 163	$ 606

For the Three Months Ended September 30, 2005	**Qualified Pension Plan**	**Supplemental Pension Plan**	**Post-Retirement Benefit Plan**	**Total**
		(In thousands)		
Service cost	$ 221	$ 35	$ 77	$ 333
Interest cost	515	73	267	855
Expected return on plan assets	(603)	0	(236)	(839)
Amortization of the transition obligation	0	0	83	83
Amortization of prior service cost	43	9	(59)	(7)
Recognized net actuarial gain	49	6	56	111

Net periodic pension benefit cost	$	225	$	123	$	188	$	536

For the Nine Months Ended September 30, 2006		**Qualified Pension Plan**		**Supplemental Pension Plan**		**Post-Retirement Benefit Plan**		**Total**
				(In thousands)				
Service cost	$	957	$	75	$	243	$	1,275
Interest cost		1,593		225		750		2,568
Expected return on plan assets		(1,931)		0		(726)		(2,657)
Amortization of the transition obligation		0		0		243		243
Amortization of prior service cost		93		57		(186)		(36)
Recognized net actuarial gain		300		36		189		525
Net periodic pension benefit cost	$	1,012	$	393	$	513	$	1,918

For the Nine Months Ended September 30, 2005		**Qualified Pension Plan**		**Supplemental Pension Plan**		**Post-Retirement Benefit Plan**		**Total**
				(In thousands)				
Service cost	$	663	$	105	$	231	$	999
Interest cost		1,545		219		801		2,565
Expected return on plan assets		(1,809)		0		(708)		(2,517)
Amortization of the transition obligation		0		0		249		249
Amortization of prior service cost		129		27		(177)		(21)
Recognized net actuarial gain		147		18		168		333
Net periodic pension benefit cost	$	675	$	369	$	564	$	1,608

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 one-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 2006 and 2005 were $132,000 and $137,000, respectively. The Company's matching and non-matching contributions for the first nine months of 2006 and 2005 were $393,000 and $380,000, respectively.

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 and unvested stock grants.

Reconciliation of income and shares used in computing fully diluted earnings per share	**Three months ended September 30**		**Nine months ended September 30**	
(In thousands)	**2006**	**2005**	**2006**	**2005**
Net income applicable to common stock	$ 2,884	$ 2,542	$ 8,522	$ 7,902
Weighted average number of common shares-basic	5,280	5,208	5,261	5,185
Dilutive effect of stock options	82	93	77	99
Weighted average number of common shares-diluted	5,362	5,301	5,338	5,284

Stock-Based Compensation
During the year ended December 31, 2000, the Company granted options for 335,300 shares under its 2000 Stock Incentive Plan exercisable over vesting schedules of between one and four years. During 2003, 2002 and 2001, the Company granted additional options of 4,000, 80,300 and 56,450, respectively. The Company has discontinued granting stock options.

During 2004, the Company's Board of Directors, with subsequent approval of the Company's common shareholders, established the 2004 Stock Incentive Plan, under which 225,000 shares in the form of stock grants, options, stock appreciation rights, restricted stock and restricted stock units, performance awards or other stock-based awards can be granted to any employee, officer, consultant, contractor or director providing services to the Company, or its subsidiaries. Effective January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123(revised 2004), Share-Based Payment (“SFAS 123R”), using the Statement’s modified prospective application method. Accordingly, prior periods have not been restated.

Prior to the adoption of SFAS 123R, the Company followed the prospective method of accounting for stock-based compensation under SFAS 148, *Accounting for Stock-Based Compensation,* beginning January 1, 2003. Stock options granted since January 1, 2003 have been expensed.

All of the Company’s stock-based compensation is based on grants of equity instruments and no liability awards have been granted. Unrestricted stock grants and deferred stock unit awards have been made only to employees, senior management and directors. Unrestricted stock grants vest immediately and are recognized as compensation expense based on the fair value of the awards at the grant date. During the nine months ended September 30, 2006 and 2005, the Company granted 14,350 shares and 14,450 shares of unrestricted stock to employees with a weighted average grant date fair value of $33.29 per share, and $29.87 per share, respectively.

Deferred stock unit awards are recognized as deferred compensation based on the fair value of the award at the grant date and charged ratably to expense over the required service period for each award, which generally equals the vesting period. Stock unit awards to senior management vest over a two-year service period, unless such senior management is retirement eligible. Certain officer awards became retirement eligible in the third quarter of 2006. The stock unit awards for retirement eligible senior management are then deemed vested and the applicable expense recognized. For the three months ended September 30, 2006, $75,000 was recognized as expense for such stock unit awards to retirement eligible officers. Stock unit awards may be deferred and earn the equivalent of dividends during the deferral period. No modifications of existing awards occurred. All shares issued for stock awards are new shares. Total compensation expense from all stock awards to directors, employees and senior management totaled $1.0 million and $737,000, for the three months ended September 30, 2006 and 2005, respectively, and $1.5 million and $913,000 for the nine months ended September 30, 2006 and 2005, respectively. The summary table of stock unit awards activity reflects all stock award compensation, but does not reflect the “retirement eligible” stock units as vested.

Stock awards	**Total Stock Awards**	**Vested Stock Awards**	**Non-vested Stock Awards**	**Average Grant-date fair value**	**Aggregate Intrinsic Value**	**Shares returned for income tax withholding**	**Compensation cost recognized**
		Share units					
Outstanding at December 31, 2005	58,566	7,166	51,400	$ 27.12	$ 1,588,310	-	$ -
Shares granted or dividend equivalents earned	400	400	-	29.00	11,600	154	11,598
Vested	-	17,600	(17,600)	24.10	424,160	5,455	202,092
Issued	(20,540)	(20,540)	-	24.13	(495,630)		
Outstanding at March 31, 2006	38,426	4,626	33,800	$ 28.69	$ 1,102,442	5,609	$ 213,690
Shares granted or dividend equivalents earned	45,770	300	45,470	28.30	1,295,291	19	232,400
Vested	-	16,900	(16,900)	29.10	491,790		
Issued	(17,200)	(17,200)	-	29.10	(500,520)	4,956	
Outstanding at June 30, 2006	66,996	4,626	62,370	$ 28.32	$ 1,897,327	10,584	$ 446,090
Shares granted or dividend equivalents earned	21,173	13,773	7,400	33.34	705,908		1,032,708
Vested	-				-		
Issued	(13,650)	(13,650)	-	33.53	(457,753)	4,872	0
Outstanding at September 30, 2006	74,519	4,749	69,770	$ 28.77	$ 2,143,912	15,456	$ 1,478,798

Approximately $1.1 million of unrecognized share-based compensation exists at September 30, 2006, with a weighted average accrual period of 18 months remaining. The amount capitalized as part of the cost of assets was approximately $5,000.

A summary of stock option activity follows:

Options	**Total Options**	**Weighted Average Price**	**Aggregate Intrinsic Value**	**Average Contractual Life in years**
Outstanding and exercisable at December 31, 2005	146,600	$ 10.90	$ 2,586,686	
Granted	-	-		
Exercised	4,500	10.22	83,248	
Forfeited	-	-		
Outstanding and exercisable at March 31, 2006	142,100	$ 10.92	$ 2,504,249	4.9
Granted				
Exercised	7,400	9.78	156,317	
Forfeited				
	134,700	$ 10.98	$ 3,092,821	4.66

Outstanding and exercisable at June 30, 2006							
Granted							
Exercised	9,600	$	13.62		191,961		
Forfeited							
Outstanding and exercisable at September 30, 2006	125,100	$	10.78	$	2,832,718		4.37

For the nine months ended September 30, 2006, cash received from the exercise of options totaled approximately $249,000 and the Company recognized a reduction in income tax liability of approximately $381,000. The adoption of SFAS 123R resulted in no incremental stock-based compensation expense and had no impact on net income, diluted earnings per share or cash flows from operating or financing activities for this same period.

Upon consummation of the proposed merger discussed under "Mergers and Acquisitions", all of the remaining unexercised stock options convert to shares, and any remaining unvested stock grants immediately vest. As a result, any unrecognized share-based compensation will be recorded in the period the merger is completed.

The information presented below has been determined as if the Company accounted for all past employee, senior management and director stock options under the fair value method.

Pro-forma net income (In thousands, except per share amounts)	Three months ended September 30 2006	 2005	Nine months ended September 30 2006	 2005
Net income reported	$ 2,884	$ 2,542	$ 8,522	$ 7,902
Pro-forma net income	2,884	2,542	8,522	7,902
Share based compensation, net of tax included in net income	614	438	879	38
Share based compensation, net of tax not included in net income	-	-	-	-
Earnings per share				
As reported-basic	$ 0.55	$ 0.49	$ 1.62	$ 1.52
Pro-forma basic	0.55	0.49	1.62	1.52
As reported-diluted	0.54	0.48	1.60	1.50
Pro-forma diluted	0.54	0.48	1.60	1.50

Long Term Debt and Credit Facilities

Effective June 14, 2006, the Company has a five year revolving credit facility of $30 million with Sovereign Bank and Key Bank replacing the expiring 364-day revolving credit agreement with Bank of America, joined by Sovereign Bank. The Sovereign/Key Bank revolving credit facility is unsecured, and allows the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. This revolving credit facility does not include any material adverse change or material adverse effect clauses, subsequent to the effective date, as pre-conditions for borrowing under the facility.

On August 3, 2006, the Company closed on the first tranche of the new $30 million First Mortgage Bonds, 6.53% Series, due August 1, 2036 and received $11 million in funds. The primary use of these funds will be to partially fund additional capital investments by the Company in Transco. It is anticipated that the second tranche of $19 million will close in December 2006 to repay $14 million of First Mortgage Bonds maturing in November and December 2006 and to repay short-term bank borrowings.

Unregulated Operations

The VPSB does not regulate our rental water heater program. The results of this 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, 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 Electric Power Company, Inc. ("VELCO")
Vermont Transco LLC ("Transco")

VELCO Percent ownership: 29.2%
Transco Percent ownership: 20.1%

In June 2006, VELCO's Board of Directors approved a plan to transfer substantially all of VELCO's business to Transco, a Vermont limited liability company. On June 30, 2006, VELCO's assets were transferred to Transco in exchange for 2.4 million Class A Membership Units and Transco's assumption of VELCO's debt. VELCO and its employees will manage the operations of Transco under an operating agreement that includes the Company, Central Vermont Public Service Corporation and most of Vermont's electric utilities. Transco is operating under Amended and Restated Three Party Agreements that include the Company, Central Vermont Public Service Corporation, VELCO and Transco. VELCO has a 54.2 percent ownership interest in Transco.

On June 30, 2006, the Company invested $6.2 million in Transco. On July 31, 2006, the Company invested an additional $300,000 in Transco made available through oversubscription rights. On September 28, 2006, the Company invested an additional $9.7 million in Transco. The total of these investments entitled the Company to receive a 20.1 percent equity ownership interest represented by Class A Membership Units in Transco that will receive an 11.5 percent rate of return.

Subsequent to September 30, 2006, the Company invested an additional $983,000 in Transco made available through oversubscription rights. As of October 31, 2006 the Company's direct percent ownership in Transco has increased to 21.9 percent.

Transco will 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 additional capital investments of up to $19 million in Transco, in support of various transmission projects. The Company's capital contributions to Transco are based on, and consistent with, our original equity commitments to VELCO.

Summarized unaudited consolidated financial information for VELCO is as follows:

VELCO Consolidated	**Unaudited**			
	Three Months Ended September 30		**Nine Months Ended September 30**	
(In thousands)	**2006**	**2005**	**2006**	**2005**
Gross Revenue	$ 7,745	$ 7,248	$ 25,201	$ 22,754
Net Income	1,348	739	2,850	2,213
Equity in Net Income, excluding Transco LLC	161	214	612	642
Amounts due from VELCO	3,233	2,681	3,233	2,681
Costs of transmission services provided by VELCO*	(1,291)	(4,181)	3,465	2,086
Construction revenues received from VELCO	1,264	1,676	1,672	2,390
*Net of allocated regional ISO-NE credits				

Summarized unaudited financial information for Transco is as follows:

Transco	**Unaudited**			
	Three Months Ended September 30		**Nine Months Ended September 30**	
(In thousands)	**2006**	**2005**	**2006**	**2005**
Gross Revenue	$ 7,849	$ -	$ 7,849	$ -
Net Income	2,060	-	2,060	-
Equity in Net Income	180	-	180	-

Included in the Company's retail and other revenues are construction services revenue of approximately $1.3 million and $1.7 million billed to VELCO in the third quarter of 2006 and 2005, respectively.

Vermont Yankee Nuclear Power Corporation ("VYNPC")
Percent ownership: 33.6% common

Summarized unaudited financial information for VYNPC is as follows:

Vermont Yankee Nuclear Power Corporation	**Unaudited**			
	Three Months Ended September 30		**Nine Months Ended September 30**	
(In thousands)	**2006**	**2005**	**2006**	**2005**
Gross Revenue	$ 56,096	$ 41,918	$ 156,456	$ 125,227
Net Income Applicable to Common Stock	208	169	549	511
Equity in Net Income	70	57	185	172
Amounts due to VYNPC	3,296	2,862	3,296	2,862

On July 31, 2002, VYNPC announced that the sale of the Vermont Yankee ("VY") nuclear plant to Entergy Nuclear Vermont Yankee, LLC ("ENVY") had been completed. Since the Company no longer owns an interest in the VY nuclear plant, we are not responsible for the costs of decommissioning the plant, nor are we responsible for any plant repairs or maintenance costs during outages.

ENVY 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. ENVY received approval from the Vermont legislature in 2005 and the VPSB in April 2006 to construct and use such dry fuel storage facilities.

On June 18, 2004, a fire in the electrical conduits leading to a transformer outside the plant resulted in a shutdown of the VY nuclear 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 a part of ENVY's request to uprate or increase the output of the VY nuclear plant that was approved by the VPSB. Under the RPP, we have indemnification rights 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. ENVY disputes that the fire was uprate-related. The Company petitioned the VPSB to resolve the dispute. In March 2006, the Company and ENVY agreed to a settlement that would pay amounts to the Company sufficient to eliminate the deferred outage costs of approximately $500,000. The settlement agreement is subject to VPSB approval.

The VY nuclear plant received final approval for uprating from the Nuclear Regulatory Commission on March 2, 2006. Since that time the VY nuclear plant output has increased to the expected uprated power level of 120 percent or 620 megawatts. While the Company has been receiving its normal share at contract rates, it is temporarily obligated to purchase a share of uprate power at market rates. On a pre-tax basis, these purchases amounted to $4.5 million for the nine months ending September 30, 2006 but there is limited effect on the Company's net income because the Company is reselling most of such power to ISO New England ("ISO-NE") at the same market rates.

The purchased power agreement between ENVY and VYNPC specifies that our percentage of energy output under VYNPC's contract with ENVY declines after the VY nuclear plant uprating is completed. The Company believes its share of the plant's output should be equivalent to the amount of power it received before the uprate process began. VYNPC and ENVY are discussing the calculations which depend upon determination of the pre-uprate capability of the plant, which is presently disputed. The Company estimates the potential impact of the differing methods of calculation will adversely affect power supply expense by up to $600,000 annually. In the event that the VY nuclear plant is derated in the future, then our rights to energy output could decline proportionately to such derating. If this were to occur, we estimate it would have a material adverse effect on our power supply costs. In this event we would seek recovery of these costs from the VPSB.

The Company is currently a party to a VPSB Docket that was opened to investigate whether the reliability of the increased nuclear plant output will be adversely affected by the operation of the plant's steam dryer. On September 18, 2006, the VPSB issued a ruling requiring ENVY to provide additional ratepayer protections that would make Vermont ratepayers whole in the event that VY must reduce power due to uprate-related steam dryer failure. Under the VPSB ruling, these protections will only apply to incremental replacement power costs incurred due under the terms of the Purchase Power Agreement ("PPA") between ENVY and VYNPC. The additional ratepayer protections are required to remain in effect through a period two months after the first refueling outage in which VY operates successfully with no steam dryer-related outages or derates. VY's next scheduled refueling outage is presently scheduled for early 2007.

ENVY has requested reconsideration of the VPSB ruling and that request remains pending.

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.

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 $5.7 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 $13.3 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 began 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**.**

Revenue Recognition
Under the Company’s most recent rate order, itsregulated earnings are limited to its allowed rate of return on equity of 10.5 percent for the period January 1, 2003 through December 31, 2006. Costs that are not allowed for rate setting purposes reduce the Company’s earning potential and limit its ability to achieve the allowed rate of return on equity for its operations as a whole. If earnings above the allowed return on equity are recorded in 2006, they will be applied to reduce regulatory assets, or possibly refunded to customers as a credit on customer bills, as directed by the Department of Public Service. For the three months ending September 30, 2006, the Company deferred $3.3 million of revenue pre-tax consistent with this restriction on earnings, and recorded a regulatory liability. We estimate the nine month adverse effect on earnings to be approximately 63 cents per share. The Company’s earnings restriction calculation is reviewed by the VPSB and is subject to change.

Retail Rate Cases
During February 2006, the Company requested that the VPSB grant an accounting order to allow us to defer approximately $3.7 million in incremental hurricane-related power supply expenses to be incurred in the first quarter of 2006, and to also allow the Company to defer and amortize $1.3 million of incremental hurricane-related benefits realized in the fourth quarter of 2005 against these costs. The accounting order was approved by the VPSB in February 2006, and allowed the Company to defer power supply expenses of $2.1 million in the first quarter of 2006.

On April 14, 2006, the Company petitioned the VPSB to increase retail rates by 11.95 percent the (“2006 Retail Rate Filing”). The rate increase is required to recover costs of providing electric service to our customers. Approximately 88 percent of the increase is due to rising power costs and the remaining 12 percent is due to expected increased transmission costs. The power cost increase is driven largely by the need to replace the Morgan Stanley contract expiring at the end of this year, and by the higher-cost, post-Katrina wholesale market. The expected increased transmission costs are largely attributable to reliability-related projects planned or under construction within the state and region. If the VPSB does not allow our full rate requirements, we estimate that for every 1 percent shortfall in rates, the financial impact could be up to a $2.0 million reduction in pre-tax earnings.

On April 14, 2006, the Company also filed for approval of an Alternative Regulation Plan. A principal component of the Plan includes a power supply adjustment mechanism that will allow the Company to adjust rates on a quarterly basis to reflect power supply cost changes in excess of $300,000 plus 90 percent of amounts in excess of $300,000 per quarter. The Plan also proposes an earnings sharing mechanism to permit sharing of earnings in excess of the Company’s allowed return on equity and earnings shortfalls below the Company’s allowed return on equity. The earnings sharing proposal, if approved, would allow the Company to earn up to 75 basis points above its allowed return on equity and would allow the Company to recover earnings shortfalls in excess of 100 basis points below its allowed return on equity. The Plan will also create opportunities and incentives for the Company to become more efficient, improve customer service, remove incentives to benefit from increased electricity sales, streamline cost recovery, share efficiency savings with customers, increase credit quality, and reduce regulatory and borrowing costs borne by customers. The Company expects the VPSB to rule on the Plan on or before April 15, 2007. Under Vermont law, an alternative regulation plan may become effective 30 days after VPSB approval.

On August 22, 2006, GMP reached a settlement with the Department in both the Company’s 2006 Retail Rate Filing and the Alternative Regulatory Plan. Not all intervening parties joined the settlement. If the rate case settlement is approved by the VPSB, the Company’s rates would increase 9.58 percent above existing rates effective January 1, 2007. If the VPSB also approves the Alternative Regulatory Plan, savings included in that plan would reduce the rate increase to 9.09 percent. We expect the VPSB to issue a final order on the 2006 Retail Rate Filing no later than December 29, 2006, and new rates to be effective January 1, 2007.

MERGERS AND ACQUISITIONS
On June 22, 2006, the Company announced that it had entered into an Agreement and Plan of Merger, dated as of June 21, 2006 (the “Merger Agreement”), among Northern New England Energy Corporation, a Vermont corporation (“NNEEC”), Northstars Merger Subsidiary Corporation, a Vermont corporation and a wholly-owned subsidiary of NNEEC (the “Merger Sub”), and the Company, pursuant to which Merger Sub will be merged with and into the Company (the “Merger”). The Company will be the surviving company in the Merger as a wholly-owned subsidiary of NNEEC. NNEEC is a wholly owned subsidiary of GazMétro Limited Partnership, a limited partnership organized under the laws of the Province of Québec (“GazMétro”).

Under the terms of the Merger Agreement, at the effective time of the Merger, each issued and outstanding share of the Company’s common stock, par value $3.33 1/3 per share (other than shares which are held by any wholly-owned subsidiary of the Company or in the treasury of the Company or which are held by NNEEC or Merger Sub, or any direct or indirect wholly-owned subsidiary of NNEEC, all of which shall cease to be outstanding and shall be canceled and none of which shall receive any payment with respect thereto, and other than dissenting shares), will be converted into the right to receive $35.00 in cash, without interest thereon.

The Company and NNEEC have made customary representations, warranties and covenants in the Merger Agreement. In particular, the Company covenants to NNEEC, subject to certain exceptions, (1) not to solicit or knowingly encourage or facilitate the making or submission of any alternative acquisition proposal nor initiate, encourage, or participate in any discussions or negotiations with, or furnish any non-public information to, any person (other than NNEEC or Merger Sub) in connection with any acquisition proposal; (2) for its Board of Directors not to withdraw or modify the Board's action to recommend the Merger in a manner adverse to NNEEC; and (3) to use its best efforts to convene a special meeting of the Company’s shareholders to consider and vote upon the approval of the Merger Agreement and the Merger.

On June 21, 2006, Merger Sub entered into employment agreements with the following employees of the Company: Christopher L. Dutton, Robert J. Griffin, Mary G. Powell, Donald J. Rendall, Jr., Robert E. Rogan, Walter Oakes and Dawn D. Bugbee. These agreements generally provide that they shall become effective upon consummation of the Merger and that the employees subject to the employment agreements will continue to be employed by the Company for a period of at least three years thereafter. Each agreement contains provisions relating to compensation, benefits, the applicable employee’s rights upon a Change of Control (as such term is defined in the employment agreement), confidentiality and the effect of the termination of an employee’s employment.

A more complete description of the terms of the proposed Merger is set forth in the Company's Current Report on Form 8-K dated June 22, 2006.

On October 31, 2006, a special meeting of the Company’s shareholders was held in Colchester, Vermont to vote on the proposal to approve the agreement and plan of merger so that the Merger can occur. At such meeting, the Company’s shareholders approved the agreement and plan of merger.

A petition for approval of the Merger was filed with the VPSB on August 7, 2006 and with the Federal Energy Regulatory Commission on August 9, 2006. These petitions remain pending. In addition, NNEEC filed an application with the Maine Public Utilities Commission for necessary regulatory approval on August 17, 2006, which was obtained on October 10, 2006. The Company and NNEEC filed their applications under the Hart Scott Rodino Antitrust Improvements Act on October 23, 2006. The Hart-Scott-Rodino 30-day waiting period has received early termination from the Federal Trade Commission and the U.S. Department of Justice.

Power Supply Risks and Contingencies
The Company meets approximately 90 percent of its customer demand through a series of long-term physical and financial contracts. The Company’s most significant power supply contracts are the Hydro Quebec Vermont Joint

Owners ("VJO") Contract (the "VJO Contract") and VYNPC Contract (the "VYNPC Contract"), which together cover approximately 75 percent of our retail load. The Company has also entered into a contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract") designed to manage wholesale electricity price risks associated with changing fossil fuel prices. The Morgan Stanley Contract supplies approximately an additional 13 percent of our load and expires December 31, 2006. See Power Contract Commitments and Related Risks - JPMorgan Energy Services, Management's Discussion and Analysis.

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	13%	Confidential*
JP Morgan	JP Morgan	Yes	System Power	10%	Confidential*

**These contract terms are subject to a confidentiality agreement.*

During the second quarter of 2006, the Company entered into a contract with JPMorgan Ventures Energy Corporation to purchase just under 10 percent of the Company's retail load requirements for a four year period commencing January 1, 2007 and ending December 31, 2010. Following expiration of the Morgan Stanley Contract and after commencement of the contract with JPMorgan Ventures Energy Corporation, the Company will have approximately 10 percent of its off-peak load exposed to market prices during the period 2007 - 2010 as well as peak and off-peak load variances caused by weather variations or other factors. Management will continue to monitor the markets for opportunities to cover the Company's open position or purchase this energy in the spot market. The replacement power costs reflected in the JPMorgan Ventures Energy Corporation agreement and the forecasted costs of the Company's remaining open position are included in the Company's 2006 Retail Rate Filing.

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 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 settled the dispute in October 2006 for $100,000.

4. DERIVATIVE INSTRUMENTS

The Company utilizes derivative instruments primarily to reduce power supply risk. The Company does not hold trading positions, seeking instead to keep supply and demand in balance. The Company has continued to record expense related to contracts which are considered derivatives in the period settled consistent with an accounting order issued by the VPSB.

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. Absent the accounting order, SFAS 133 would require that changes in the derivative’s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Since we are required under a VPSB order to defer recognition of any SFAS 133 earnings effect until settled, we do not evaluate derivatives for hedge accounting treatment.

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. From time to time, we use forward contracts to hedge the 9701 agreement. If the Company were to terminate or sell any of its derivative contracts, it would immediately record the gain or loss on that contract. For derivatives held to maturity, the earnings impact would be recorded in the period that the derivative is sold or matures.

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.

The JPMorgan Ventures Energy Corporation Contract is used to hedge against fossil fuel price increases. This contract is a derivative but meets the exception for a normal purchase and sale contract, and therefore does not require the recording of an asset or liability.

At September 30, 2006, the Company had a power supply derivative liability of $18.1 million recorded in deferred credits and $4.9 million recorded in current liabilities totaling the $23.0 million fair value of the 9701 agreement. Also at September 30, 2006, the Company had a derivative asset of $2.0 million, reflecting the fair value of the Morgan Stanley Contract with corresponding regulatory assets and regulatory liabilities total $23.0 million and $2.0 million, respectively. Amounts due during the next twelve months are classified in current assets and current liabilities. At December 31, 2005, the Company had a liability of $30.1 million, reflecting the fair value of the 9701 agreement and an asset of $15.3 million, reflecting the fair value of the Morgan Stanley Contract with corresponding regulatory assets and regulatory liabilities total $30.1 million and $15.3 million, respectively. Amounts due during 2006 are classified in current assets and current liabilities.

In March 2006, the Company entered into an interest rate swap relating to the Company's 2006 issuance of first mortgage bonds to mitigate the risk of rising interest rates. See LIQUIDITY AND CAPITAL RESOURCES. Approximately one-half of the new $30 million first mortgage bonds in 2006 was covered. The interest rate swap was settled on August 2, 2006, with a final gain on settlement of approximately $600,000, which will be amortized over the life of the bond issue as a component of interest expense.

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 the rental water heater program in the Other Income section in the Consolidated Statement of Income.

6. NEW ACCOUNTING STANDARDS

Recent Accounting Pronouncements

In December 2004, the FASB issued SFAS 123R, which revises SFAS 123 and supersedes APB 25 and its related implementation guidance. SFAS 123R focuses primarily on accounting for share-based payments to employees in exchange for services, and it requires entities to recognize compensation expense for these payments. The cost for equity-based awards is expensed based on their grant date fair value, and liability awards are expensed based on their fair value, which is re-measured each reporting period. The pro forma disclosure previously permitted under SFAS 123 is no longer an alternative to financial statement recognition. The Company uses the fair value method for share-based payment awards. This new standard did not have a material impact on the Company's financial position, its results of operations or its liquidity.

On May 25, 2005, the Financial Accounting Standards Board ("FASB") issued Statement No. 154, *Accounting Changes and Error Corrections - a replacement of APB Opinion No. 20 and FASB Statement No. 3* ("SFAS 154"). This Statement replaces APB Opinion No. 20, Accounting Changes, and FASB Statement No. 3, *Reporting Accounting Changes in Interim Financial Statements*, and changes the requirements for the accounting for and reporting of a change in accounting principles. This Statement applies to all voluntary changes in accounting principle and changes required by an accounting pronouncement in the instance that the pronouncement does not include specific transition provision. Effective January 1, 2006, the adoption of SFAS 154 had no effect on the financial statements of the Company.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, "Fair Value Measurements" (SFAS No. 157). SFAS No. 157 redefines fair value as "the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date." SFAS No. 157 establishes a fair value hierarchy that categorizes and prioritizes the inputs that should be used to estimate fair value. We will implement SFAS No. 157 as of January 1, 2008, applying the provisions retrospectively for derivative accounting and prospectively for all other valuations. We are currently evaluating the impact adoption may have on our financial condition, results of operations and cash flows.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)" (SFAS 158). SFAS 158 requires company plan sponsors to display the net over- or under-funded position of a defined benefit postretirement plan as an asset or liability, with any unrecognized prior service costs, transition obligations or actuarial gains/losses reported as a component of other comprehensive income in shareholders' equity. The provisions of SFAS 158 are effective for fiscal years ending after December 15, 2006.

The Company is currently evaluating the potential impact of this Statement on the Condensed Consolidated Financial Statements. The Company intends to record a regulatory asset and is seeking to obtain an accounting order to defer the effects of this new accounting standard. If the Company is not successful in obtaining an accounting order to defer the effects, based on current estimates, Accumulated Other Comprehensive Income would increase by $5.2 million, net of tax, and Retained Earnings would decrease by $1.5 million, net of tax. If the Company is successful in obtaining an accounting order for deferral, regulatory assets would be created in lieu of adjustments to Retained Earnings.

In June 2006, the FASB issued FIN-48**,** Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109, effective for fiscal years beginning after December 15, 2006. This interpretation clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes. The adoption of FIN-48 by the Company is expected to have no effect on results of operations or financial position.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

From time to time in this report, we may make statements that constitute “forward-looking statements” within the meaning of the “safe-harbor” provisions of the Private Securities Litigation Reform Act of 1995. Such statements are based on our then current expectations and are subject to a number of risks and uncertainties that could cause actual results to differ materially from those addressed in the forward-looking statements. 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 and other regulatory risks;
- energy supply and demand, outages and other power supply volume risks;
- power supply price risks;
- customer concentration risks;
- pension and postretirement health care risks;
- customer service quality;
- changes in regional market and transmission rules;
- contractual commitments;
- credit risks, including availability, terms, and use of capital and counterparty credit quality;
- general economic and business environment;
- changes in technology;
- nuclear and environmental issues;
- alternative regulation and cost recovery (including stranded costs);
- weather;
- Rapidly changing and increasingly competitive wholesale electricity utility markets;
- Customer growth and changes in customer demands; and
- Acts of terrorism.

Executive Overview

Green Mountain Power Corporation (the "Company") typically 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. In periods of very high energy prices, wholesale revenues and expenses arising primarily from sales and purchases to accommodate volumetric difference between energy supplies and customer demand can affect earnings to a significant degree. The Company is regulated and cannot adjust prices of retail electricity sales without regulatory approval from the Vermont Public Service Board ("VPSB").

On June 22, 2006, the Company announced that it had entered into an Agreement and Plan of Merger, dated as of June 21, 2006 (the “Merger Agreement”). A complete description of the terms of the proposed Merger Agreement is set forth in the Company’s current report on Form 8-K dated June 22, 2006.

On October 31, 2006, a special meeting of the Company’s shareholders was held in Colchester, Vermont to vote on the proposal to approve the agreement and plan of merger so that the Merger can occur. At such meeting, the Company’s shareholders approved the agreement and plan of merger.

A petition for approval of the Merger was filed with the VPSB on August 7, 2006 and with the Federal Energy Regulatory Commission on August 9, 2006. These petitions remain pending. In addition, NNEEC filed an application with the Maine Public Utilities Commission for necessary regulatory approval on August 17, 2006, which was obtained on October 10, 2006. The Company and NNEEC filed their applications under the Hart Scott Rodino Antitrust Improvements Act on October 23, 2006. The Hart-Scott-Rodino 30-day waiting period has received early termination from the Federal Trade Commission and the U.S. Department of Justice.

The Company increased its common stock dividend in February 2006 from an annual rate of $1.00 per share to $1.12 per share. The Company's dividend payout ratio during 2005 was comparatively low, at approximately 48 percent of 2005 earnings from continuing operations. The Merger Agreement permits the Company to pay quarterly dividends of $0.28 per share. Under the Merger Agreement, the Company has agreed not to increase the dividend prior to the closing of the Merger without the permission of NNEEC.

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. The Company's allowed rate of return on its regulated operations is currently capped at 10.5 percent, reduced by amounts normally excluded for purposes of setting rates and is determined by the VPSB. Nearly all of the Company's continuing operations are treated for ratemaking purposes as regulated operations. The Company's 2005 return on equity was 9.85 percent reflecting the exclusions mentioned above. These exclusions also make it unlikely that the Company's operating results will achieve its allowed rate of return while its earnings are subject to the earnings cap. The Company is currently operating under a three-year rate plan approved by the VPSB in December 2003 (the "2003 Rate Plan"). The 2003 Rate Plan covers the period 2004 - 2006 and has provided the Company with a stable, predictable rate path through 2006, a plan for full recovery of the Company's principal regulatory assets, and an improved opportunity to earn a fair rate of return.

On April 14, 2006, the Company petitioned the VPSB to increase retail rates by 11.95 percent the ("2006 Retail Rate Filing"). The rate increase is required to recover costs of providing electric service to our customers. Approximately 88 percent of the increase is due to rising power costs and the remaining 12 percent is due to expected increased transmission costs. The power cost increase is driven largely by the need to replace the Morgan Stanley contract expiring at the end of this year, and by the higher-cost, post-Katrina wholesale market. The expected increased transmission costs are largely attributable to reliability-related projects planned or under construction within the state and region. If the VPSB does not allow our full rate requirements, GMP estimates that for every 1 percent shortfall in rates, the financial impact could be up to a $2.0 million reduction in pre-tax earnings.

On April 14, 2006, the Company also filed for approval of an Alternative Regulation Plan. A principal component of the Plan includes a power supply adjustment mechanism that will allow the Company to adjust rates on a quarterly basis to reflect power supply cost changes in excess of $300,000 plus 90 percent of amounts in excess of $300,000 per quarter. The Plan also proposes an earnings sharing mechanism to permit sharing of earnings in excess of the Company's allowed return on equity and earnings shortfalls below the Company's allowed return on equity. The earnings sharing proposal, if approved, would allow the Company to earn up to 75 basis points above its allowed return on equity and would allow the Company to recover earnings shortfalls in excess of 100 basis points below its allowed return on equity. The Plan will also create opportunities and incentives for the Company to become more efficient, improve customer service, remove incentives to benefit from increased electricity sales, streamline cost recovery, share efficiency savings with customers, increase credit quality, and reduce regulatory and borrowing costs borne by customers. The Company expects the VPSB to rule on the Plan on or before April 15, 2007. Under Vermont law, an alternative regulation plan may become effective 30 days after VPSB approval.

On August 22, 2006, GMP reached a settlement with the Department in both the Company's 2006 Retail Rate Filing and the Alternative Regulatory Plan. Not all intervening parties joined the settlement. If the rate case settlement is approved by the VPSB, the Company's rates would increase 9.58 percent above existing rates effective January 1, 2007. If the Board also approves the Alternative Regulatory Plan, savings included in that plan would reduce the rate increase to 9.09 percent. We expect the VPSB to issue a final order on the 2006 Retail Rate Filing no later than December 29, 2006, and new rates to be effective January 1, 2007.

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. 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.

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"), through investments in Vermont Transco, LLC ("Transco") 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. 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	
	2006	2005	2006	2005
Utility business	$ 0.54	$ 0.49	$ 1.60	$ 1.52
Unregulated businesses	0.01	-	0.02	-
Earnings per share of common stock	$ 0.55	$ 0.49	$ 1.62	$ 1.52
Basic earnings per share	$ 0.55	$ 0.49	$ 1.62	$ 1.52
Diluted earnings per share	$ 0.54	$ 0.48	$ 1.60	$ 1.50

Operating Results
The Company had consolidated earnings of $0.54 per share of common stock, diluted, for the third quarter of 2006 compared with consolidated earnings of $0.48 per share of common stock, diluted, for the same period in 2005.

Earnings increased in the third quarter of 2006 compared with the same period of 2005 primarily as a result of lower power supply and transmission costs, and an increase in utility business revenue, which were partially offset by a reduction in retail revenues of $3.3 million consistent with a restriction on earnings required in the rate agreement approved by the VPSB in 2003 in the Company's last retail rate case The decrease in power supply costs in 2006 resulted from added precipitation-based production by Company hydro power plants (which produced low-cost electricity) that replaced higher priced market purchases made during the third quarter of 2005.

Retail operating revenue for the third quarter of 2006 decreased by approximately $3.0 million compared with the same period in 2005. Of this amount, $3.3 million related to the deferral of earnings in excess of our allowed rate of return, partially offset by a $1.7 million increase related to the sale of utility construction services to commercial and municipal entities. There was a reduction in residential and commercial/industrial sales of electricity due to more seasonable weather compared to the same quarter of 2005, which was affected by very hot summer temperatures. The revenue impact from reduced sales was offset by a 0.9 percent rate increase authorized by the VPSB which generated approximately $500,000 in additional revenues during the third quarter of 2006. Sales to residential, and small and large commercial and industrial customers decreased by 3.7 percent and 4.0 percent, respectively, compared with the third quarter in 2005. Total retail megawatt hours sales of electricity decreased by 4.0 percent in the third quarter of 2006, compared with the same period in 2005.

Under the Company's most recent rate order, itsregulated earnings are limited to its allowed rate of return on equity of 10.5 percent for the period January 1, 2003 through December 31, 2006. Costs that are not allowed for rate setting purposes reduce the Company's earning potential and limit its ability to achieve the allowed rate of return on equity for its operations as a whole. If earnings above the allowed return on equity are recorded in 2006, they will be applied to reduce regulatory assets, or possibly refunded to customers as a credit on customer bills, as directed by the Department of Public Service. For the three months ending September 30, 2006, the Company deferred $3.3 million of revenue pre-tax consistent with this restriction on earnings, and recorded a regulatory liability. We estimate the nine month adverse effect on earnings to be approximately 63 cents per share. The Company's earnings restriction calculation is reviewed by the VPSB and is subject to change.

Wholesale revenues in the third quarter of 2006 increased by $78,000 compared to the same quarter in 2005. Wholesale revenues increased because we sold the excess supplies discussed above in the wholesale energy market.

In the third quarter of 2006, power supply expenses decreased by $4.3 million compared with the third quarter of 2005. Additional purchases under our contract entitlements and greater production from Company-owned hydro facilities (which produced low-cost electricity) replaced higher priced market purchases in the wholesale energy markets during the third quarter of 2005. Due to the limited hurricane activity and relatively mild summer weather in 2006, the Company paid substantially lower market prices for system purchases during hours when customer demand exceeded supply during the third quarter of 2006 compared with the same quarter in 2005.

Other operating expenses increased by approximately $1.9 million in the third quarter of 2006 compared with the same period of 2005 reflecting increased expenses of $1.3 million in the sale of utility construction services to commercial and municipal customers, costs associated with the proposed acquisition of the Company by an affiliate of GazMétro of $300,000 and increased expenses of $300,000 for employee benefits.

Transmission expenses decreased by approximately $1.1 million in the third quarter of 2006 compared with the same period last year, primarily as a result of regional transmission credits from ISO New England to VELCO.

The Company recorded diluted earnings per share of $1.60 for the nine months ended September 30, 2006, compared with diluted earnings of $1.50 per share in the same period last year. Earnings increased in the first nine months of 2006 principally as a result of $7.0 million of increased wholesale revenue exceeding the purchased power costs, partially offset by the deferral of $3.3 million of earnings in excess of our allowed rate of return.

Retail operating revenue for the first nine months of 2006 decreased $2.6 million or 1.6 percent compared with the same period in 2005 as retail megawatt sales decreased 2.4 percent. Wholesale revenues for the first nine months of 2006 increased $7.0 million compared to the same period in 2005, because we sold the excess supplies discussed above in the wholesale energy market.

Power supply expenses decreased by $1.9 million in the first nine months of 2006 compared to the same nine months in 2005. Additional purchases under our contract entitlements and greater production from Company-owned hydro facilities replaced more costly energy purchased in the wholesale energy markets during the first nine months of 2005 and resulted in excess supply that was sold in the wholesale markets.

Other operating expenses increased $5.1 million in the first nine months of 2006 compared with the same period in 2005 reflecting the $1.2 million incurred for costs associated with the Merger, increased expenses of $2.6 million in the sale of utility construction services and increased expenses of $600,000 for employee benefits.

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, 2006 and 2005 are summarized below:

	Three months ended September 30		Nine months ended September 30	
(Dollars in thousands)	2006	2005	2006	2005
Operating revenues				
Retail	$ 54,615	$ 57,584	$ 160,242	$ 162,874
Sales for Resale	6,818	6,740	21,547	14,586
Total Operating Revenues	$ 61,433	$ 64,324	$ 181,789	$ 177,460
MWh Sales-Retail	504,909	525,783	1,472,538	1,508,826
MWh Sales for Resale	126,688	74,139	350,440	209,016
Total MWh Sales	631,597	599,922	1,822,978	1,717,842

Average Number of Customers	Three months ended September 30		Nine months ended September 30	
	2006	2005	2006	2005
Residential	78,405	76,354	77,862	76,162
Commercial and Industrial	14,046	13,814	13,978	13,708
Other	62	60	62	61
Total Number of Customers	92,513	90,228	91,902	89,931

Revenues
Total operating revenues in the third quarter of 2006 decreased by $2.9 million, or 4.5, percent from the same period in 2005, primarily due to the deferred regulatory earnings of $3.3 million in excess of our allowed rate of return. 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 regulated earnings are limited to 10.5 percent. If excess earnings are recorded in 2006, they will be applied to reduce regulatory assets, or refunded to customers as a credit on customer bills, as the Department directs.

Retail operating revenues for the third quarter of 2006 decreased $3.0 million, or 5.2 percent, compared with the same period in 2005, reflecting the deferral of earnings in excess of our allowed rate of return, decreased MWh sales of electricity caused by unseasonably cooler weather, offset by the 0.9 percent rate increase authorized by the VPSB and the increase in utility construction revenues.

Total retail MWh sales of electricity in the third quarter of 2006 decreased 4.0 percent when compared with the third quarter of 2005, primarily as a result of a decrease in commercial and industrial sales of 4.0 percent and a decrease of 3.7 percent in residential sales.

The Company recognizes revenues from sales of utility construction services in retail revenues. Revenues from these activities amounted to $4.3 million in the third quarter of 2006 compared with $2.6 million in the same period last year.

Wholesale revenues for the third quarter of 2006 increased $78,000 or 1.2 percent compared with the same period in 2005 as a result of increased sales of excess power resulting from a temporary increase in our entitlement to output of the VY nuclear plant and our exercise of an option to increase deliveries under a long-term power supply contract.

Retail operating revenues decreased $2.6 million during the first nine months of 2006, compared with the same period of 2005, reflecting the deferral of regulatory earnings of $3.3 million, a decrease of $900,000, or 0.9 percent, in commercial and industrial revenues during the same comparative periods, and a decrease of approximately $1.0 million, or 1.7 percent, in revenues from residential customers, offset by a $2.7 million increase in the recognition of revenues from the sale of utility construction services.

Wholesale revenues increased $7.0 million, or 47.7 percent, during the first nine months of 2006, compared with the same period in 2005, as a result of increased sales of our excess power to the wholesale energy market.

Customer Concentration Risk
The Company's major industrial customer, International Business Machines ("IBM"), accounted for 15.2 percent, 15.3 percent and 16.2 percent of retail revenue for 2006 year to date, and the years ended 2005 and 2004, 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 decreased $4.3 million, or 10.6 percent, in the third quarter of 2006 compared with the same period in 2005. Increased 2006 entitlements to power under a long-term contract with Hydro Quebec and a temporary increase in the Company's entitlement from the Vermont Yankee nuclear power plant reduced the Company's reliance on wholesale market purchases of electricity. The additional 2006 entitlements under the Hydro Quebec contract and the Vermont Yankee output were purchased, on average, at prices below the wholesale market price for the third

quarter of 2006 and substantially below 2005 wholesale market prices. Market prices for Company purchases in the third quarter of 2006 were substantially lower than 2005, reflecting the interruption of gas supplies in the Gulf caused by hurricane activity coupled with warmer than normal summer temperatures in 2005.

Power supply expenses from VYNPC increased $2.8 million, or 33.5 percent, during the third quarter of 2006 compared with the same period of 2005, primarily due to a temporary entitlement of increased output from the VY nuclear plant purchased under our contract with VYNPC. Most of the incremental entitlement was purchased at wholesale market prices.

Company-owned generation expenses increased $847,000, or 44.5 percent, in the third quarter of 2006 compared with the same period in 2005, primarily due to increased production related fuel costs at a jointly owned plant.

The cost of power that we purchased from other companies decreased $5.1 million, or 13.3 percent, in the third quarter of 2006 compared with the same period in 2005. This was primarily due to decreased higher-cost market purchases made possible because of increased purchases of lower-cost resources, including energy under our contract with Hydro Quebec. Wholesale market prices were also substantially lower during the third quarter of 2006 than during the same period in 2005 due to less supply interruptions and milder summer temperatures.

Under the Public Utility Regulatory Policy Act of 1978 (“PURPA”), the Company must purchase the output of independent power producers (“IPP”) plants governed by this act at specific rates for specified periods of time. These specified rates are typically the highest contract rates of any contracted resources that the Company purchases. Approximately half of the output of these plants is hydro and in the third quarter of 2006, higher than normal precipitation resulted in an increase of $750,000 in purchases from these IPP plants. The benefits of additional production from our own hydro plants substantially offset the costs of IPP plant purchases.

Under the Vermont Joint Owners (including the Company) contract with Hydro Quebec, the Company exercised one of its remaining two options to increase the load factor to 80 percent from 75 percent in November 2005. Hydro Quebec exercised the first of its options under this same contract to decrease the load factor from 75 percent to 65 percent in November 2004 for the period ending October 31, 2005. As a result, the Company received approximately 50,000 additional MWh in the third quarter of 2006 at an average price of approximately $30 per MWh, well below wholesale market prices.

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 increased capacity payments 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 increased capacity payments at levels that were expected to result in substantially higher capacity payments to generators beginning January 1, 2006. The changes were disputed by numerous parties for a variety of reasons. In October 2005, FERC initiated a settlement process to consider alternatives to the proposal. Under ISO-NE’s increased capacity payment 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 capacity payments for load growth beyond 2006 could be material, and if so, would be expected to increase Company rate requirements accordingly. Based on the current ISO-NE proposal, the Company estimates that the 2007 impact of capacity price increases would raise our power supply expenses by approximately $1 million, and those costs are included in the Company’s 2006 Retail Rate Filing.

Power supply expenses decreased $1.9 million, or 1.8 percent, in the first nine months of 2006 compared with the same period in 2005. Increased 2006 entitlements to power under a long-term contract with Hydro Quebec and a temporary increase in the Company’s entitlement from the VY nuclear plant reduced the Company’s reliance on wholesale market purchases of electricity. The additional 2006 entitlements under the Hydro Quebec contract and the VY output were purchased, on average, at prices below the wholesale market price for the third quarter of 2006 and substantially below 2005 wholesale market prices. Market prices for Company purchases in the third quarter of 2006 were substantially lower than 2005, reflecting the interruption of gas supplies in the Gulf caused by hurricane activity coupled with warmer than normal summer temperatures in 2005. Incremental energy purchased from these sources that was not used to serve customer demand was sold in the wholesale energy markets at higher prices than the marginal costs for these resources, particularly for Hydro Quebec deliveries.

Power supply expenses from VYNPC increased $5.6 million, or 21.6 percent, during the first nine months of 2006 compared with the same period of 2005, primarily due to a temporary increase in purchases associated with the VY uprate, most of which was purchased at wholesale market energy prices.

Company-owned generation expenses increased $1.2 million, or 26.6 percent, in the first nine months of 2006 compared with the same period in 2005, principally because of increased output at one of our joint-owned facilities.

The cost of power that we purchased from other companies decreased $3.1 million, or 3.0 percent, in the first nine months of 2006 compared with the same period in 2005, primarily due to reduced wholesale market purchases and as a result of increased low cost energy received under our contract with Hydro Quebec, and energy from the temporarily increased output of the VY nuclear plant. Wholesale market prices were also substantially higher during the third quarter of 2005 than during the same period this year, reflecting warmer temperatures and supply interruptions.

Other operating expenses

Other operating expenses increased $1.9 million, or 27.4 percent, in the third quarter of 2006 compared with the same period in 2005 due primarily to increased expenses of $1.3 million associated with the sale of utility services to commercial and municipal customers, costs of $300,000 relating to the proposed acquisition of the Company by an affiliate of GazMétro, and increased expenses of $300,000 for employee benefits.

Other operating expenses increased $5.1 million, or 29.6 percent, in the first nine months of 2006 compared with the same period in 2005 due primarily to increased expenses of $2.6 million associated with the sale of utility services to commercial and municipal customers, costs of $1.2 million relating to the proposed acquisition of the Company by an affiliate of GazMétro, and increased expenses of $600,000 for employee benefits.

Transmission expenses

Transmission expenses decreased by $1.1 million, or 26.5 percent, for the three months ended September 30, 2006 compared with the same period in 2005, primarily as a result of regional transmission credits from ISO New England to VELCO.

Transmission expenses decreased by $60,000, or 0.5 percent, for the nine months ended September 30, 2006 compared with the same period in 2005 for the same reasons. The Company's relative share of transmission expenses allocated from VELCO varies with the Company's relative share of the peak demand recorded on Vermont's transmission system.

Maintenance expenses

Maintenance expenses decreased by $178,000, or 6.3 percent, in the third quarter of 2006 compared with the same period of 2005 primarily due to a decrease in scheduled plant maintenance and turbine repairs.

Maintenance expenses increased $109,000, or 1.4 percent, for the nine months ended September 30, 2006 compared with the same period in 2005 due to an increase in scheduled plant maintenance and software maintenance costs.

Depreciation and amortization expenses

Depreciation and amortization expenses for the quarter ended September 30, 2006 decreased $193,000 or 5.1 percent compared with the same period in 2005, reflecting a decrease in the depreciation of utility plant reflecting an updated depreciation study.

Depreciation and amortization expenses decreased $505,000, or 4.5 percent, for the nine months ended September 30, 2006 compared with the same period in 2005 for the same reasons.

Taxes other than income taxes
Other tax expense for the third quarter of 2006 increased by $144,000, or 9.4 percent, compared with the same period in 2005 due to increases in property tax.

Other tax expense for the first nine months of 2006 increased slightly by $149,000, or 3.0 percent, compared with the same period in 2005 for the same reason.

Income taxes
Income taxes increased $567,000, or 63.5 percent, in the third quarter of 2006 compared with the same period in 2005 due to an increase in pretax book income and an increase in the effective tax rate due to nondeductible merger expenses. Income taxes increased $1.0 million, or 26.6 percent, in the first nine months of 2006 compared with the same period in 2005 due to an increase in pretax book income and an increase in the effective tax rate due to nondeductible merger expenses, partially offset by a decrease in the Vermont state income tax rate.

Interest charges
Interest charges increased $228,000, or 13.5 percent, in the third quarter of 2006 compared with the same period in 2005, due to an increase in interest expense on the Company's revolving line of credit and a tax obligation, and the issuance of $11.0 million of first mortgage bonds in August 2006. Interest charges increased $350,000, or 6.9 percent, for the first nine months of 2006 compared with the same period in 2005 for the same reasons.

LIQUIDITY AND CAPITAL RESOURCES
At December 31, 2005, we had cash and cash equivalents of $6.5 million. In the first nine months of 2006, cash and cash equivalents decreased to $1.1 million. Operating cash flows decreased by $11.2 million from the same period last year primarily as the result of increased working capital needs and payments for estimated income taxes. Net cash used by investing activities amounted to $28.2 million, principally for investments to construct utility plant and investments in Transco.

We expect to spend approximately $10.2 million during the fourth quarter of 2006, primarily for improvements in transmission, distribution and generation plant, and environmental expenditures. The Company plans to invest up to $25 million in Transco through 2008 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 Transco have increased from previous estimates primarily as a result of increases in VELCO's cost estimates for the NRP.

On February 27, 2006, the annual dividend rate was increased from $1.00 to $1.12 per share, a payout ratio of approximately 48 percent based on 2005 earnings from continuing operations. The Merger Agreement permits the Company to pay quarterly dividends of $0.28 per share. Under the Merger Agreement, the Company has agreed not to increase the dividend prior to the closing of the Merger without the permission of NNEEC.

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.

Effective June 14, 2006, the Company has a five year revolving credit facility of $30 million with Sovereign Bank and Key Bank replacing the expiring 364-day revolving credit agreement with Bank of America, joined by Sovereign Bank. The Sovereign/Key Bank revolving credit facility is unsecured, and allows the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. This revolving credit facility does not include any material adverse change or material adverse effect clauses, subsequent to the effective date, as pre-conditions for borrowing under the facility.

On August 3, 2006, the Company closed on the first tranche of the new $30 million First Mortgage Bonds, 6.53% Series, due August 1, 2036 and received $11 million in funds. The primary use of these funds will be to partially fund additional capital investments by the Company in Transco. It is anticipated that the second tranche of $19 million will close in December 2006 to repay $14 million of First Mortgage Bonds maturing in November and December 2006 and to repay short-term bank borrowings.

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.

The credit ratings of the Company's first mortgage bonds at September 30, 2006 were:

	Moody’s	**Standard & Poor’s**
First Mortgage Bonds	Baa1	BBB

Rating agencies reacted favorably to the announcement of the Merger Agreement with NNEEC. Both Moody’s and Standard and Poor’s placed the Company in a “positive watch” category.

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 either 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, 2006, for which undiscounted future annual payments are shown.

	Future Payments Contractually Due by Period				
At September 30, 2006	**Total**	**Remaining in 2006**	**2007 and 2008**	**2009 and 2010**	**After 2011**
			(In thousands)		
Long-term debt	$ 104,000	$ 14,000	$ -	$ -	$ 90,000
Interest on long-term debt	58,616	1,514	11,068	11,068	34,966
Capital lease obligations	3,587	119	771	771	1,927
Hydro-Quebec power supply contracts	478,015	10,418	103,020	103,993	260,583
Morgan Stanley Contract	2,228	2,228	-	-	-
Independent Power Producers	138,491	2,610	33,285	33,285	69,312
Stony Brook contract	24,914	281	3,480	3,541	17,612
VYNPC PPA	179,004	1,913	64,144	69,811	43,137
JP Morgan	75,681	-	38,166	37,515	-
Benefit plan contributions	18,500	500	4,000	4,000	10,000
VELCO capital contributions	9,570	-	9,570	-	-
Deferred Compensation	10,055	417	2,184	2,290	5,164
Total	$ 1,102,661	$ 34,000	$ 269,688	$ 266,272	$ 532,701

See the captions "Power Supply Expense" and "Power Contract Commitments" for additional information about the Hydro-Quebec, Morgan Stanley, and JP Morgan power supply contracts.

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 equity interests in VELCO and Transco, which require the Company to contribute capital when required and to pay a portion of VELCO’s and Transco’s operating costs, including its debt service costs.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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 legislation 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 2010. 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 has not historically had 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. 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. In addition, if approved, the Company’s proposed Alternative Regulation Plan will provide a power supply adjustment mechanism. See Executive Overview for a discussion about the Company’s 2006 Rate Case Filing.

Vermont Yankee - We have a 20 percent entitlement in VY nuclear plant output sold by ENVY to 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 2006, we purchased $31.4 million from VYNPC based on our entitlement share of plant output, compared to $25.8 million for the same period in 2005, reflecting the uprated capacity of the plant to produce energy and the Company’s temporarily enhanced ability to purchase the energy. The majority of these incremental purchases were at market prices by the Company.

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 2006, we purchased $41.1 million of energy and related capacity from Hydro Quebec, compared to $36.9 million for the same period in 2005.

Under the VJO Contract, Hydro Quebec had the right to reduce the load factor from 75 percent to 65 percent a total of 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 had two options to increase or reduce the load factor by 5 percent under the VJO Contract and exercised the last of these options to increase deliveries occurring principally between November 1, 2006 and October 30, 2007. The option will provide approximately 50,000 additional off-peak MWH’s of supply.

Morgan Stanley - We purchase approximately 13 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.

During the second quarter of 2006, the Company entered into a contract with JPMorgan Ventures Energy Corporation to purchase just under 10 percent of the Company’s retail load requirements for a four year period commencing January 1, 2007 and ending December 31, 2010. Following expiration of the Morgan Stanley Contract and after commencement of the contract with JPMorgan Ventures Energy Corporation, the Company will have approximately 100,000 MWh of remaining off-peak load exposed to market prices during the period 2007 - 2010. Management will continue to monitor the markets for opportunities to cover the Company’s open position or purchase this energy in the spot market. The replacement power costs reflected in the JPMorgan Ventures Energy Corporation agreement and the forecasted costs of the Company’s remaining open position are substantially included in the Company’s 2006 Retail Rate Filing.

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 $3.0 million to defined benefits plans during 2006.

Power Supply and Other 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, 2006 to be approximately $2.0 million.

We currently have an agreement (the "9701 agreement") that grants Hydro Quebec an option 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, 2006 is approximately $23.0 million. Hydro Quebec exercised its 9701 option for delivery during the first quarter of 2006.

In March 2006, the Company entered into an interest rate swap relating to the Company's 2006 issuance of first mortgage bonds to mitigate the risk of rising interest rates. Approximately one-half of the new $30 million first mortgage bonds in 2006 were covered. The interest rate swap was settled on August 2, 2006, with a final gain on settlement of approximately $600,000, which will be amortized over the life of the bond issue as a component of interest expense.

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 $3.8 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	**At September 30, 2006**	
	Fair Value(Cost)	**Market Risk**
	(In thousands)	
Morgan Stanley Contract	$ 1,994	$ 221
9701 agreement	(23,007)	(3,992)
	$ (21,013)	$ (3,771)

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 as of the end of the period covered by this report.

There has been no change in our internal control over financial reporting during the quarter ended September 30, 2006, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS
See Note 3 of Notes to Consolidated Financial Statements under Item 1 - Financial Statements.

Item 1A. RISK FACTORS
While we attempt to identify, manage and mitigate risks and uncertainties associated with our business to the extent practical under the circumstances, some level of risk and uncertainty will always be present. Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2005 describes some of the risks and uncertainties associated with our business. These risks and uncertainties have the potential to materially affect our results of operations and our financial condition. We do not believe that there have been any material changes to the risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2005.

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
At a special meeting of shareholders held on October 31, 2006, there were 5,289,161 shares of common stock outstanding and entitled to vote, of which 3,921,722 were represented in person or by proxy. The following matters were submitted to a vote of the Company’s shareholders at the special meeting with the voting results designated below each such matter:

1. Shareholders were asked to approve or disapprove the Agreement and Plan of Merger by and among the Company, Northern New England Energy Corporation and Northstars Merger Subsidiary Corporation with 3,815,744 votes for, 85,694 votes against, and 20,284 votes abstaining.

2. Shareholders were asked to approve or disapprove granting authority to proxy holders to vote in their discretion with respect to the approval of any proposal to postpone of adjourn the special meeting to a later date for a reasonable business purpose, including to solicit additional proxies in favor of the approval of the Agreement And Plan Of Merger if there are not sufficient votes for approval of the Agreement and Plan of Merger at the special meeting, with 3,680,489 votes for, 212,081 votes against, and 29,152 votes abstaining.

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 Dawn D. Bugbee, Vice President Chief Financial Officer 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 Dawn D. Bugbee, Vice President, Chief Financial Officer 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 8, 2006
Christopher L. Dutton	Date
President and	
Chief Executive Officer	
By: /s/ Dawn D. Bugbee	November 8, 2006
Dawn D. Bugbee	Date
Vice President, Chief Financial Officer	
and Principal Accounting Officer	