UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended March 31, 2009

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number **1-8222**

Central Vermont Public Service Corporation
(Exact name of registrant as specified in its charter)

Vermont (State or other jurisdiction of incorporation or organization)	**03-0111290** (IRS Employer Identification No.)
77 Grove Street, Rutland, Vermont (Address of principal executive offices)	**05701** (Zip Code)

Registrant's telephone number, including area code **(800) 649-2877**

N/A
(Former name, former address and former fiscal year, if changed since last report)

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 ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. As of April 30, 2009 there were outstanding 11,653,134 shares of Common Stock, $6 Par Value.

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
Form 10-Q for Period Ended March 31, 2009

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(dollars in thousands, except per share data)
(unaudited)

	Three months ended March 31 2009	2008
Operating Revenues	**$ 90,727**	$ 91,224
Operating Expenses		
Purchased Power - affiliates	**16,062**	16,468
Purchased Power	**25,548**	26,438
Production	**3,220**	3,342
Transmission - affiliates	**2,481**	3,389
Transmission - other	**5,695**	4,474
Other operation	**15,533**	14,745
Maintenance	**4,492**	6,169
Depreciation	**4,029**	3,869
Taxes other than income	**4,168**	4,039
Income tax expense	**2,876**	1,859
Total Operating Expenses	**84,104**	84,792
Utility Operating Income	**6,623**	6,432
Other Income		
Equity in earnings of affiliates	**4,445**	4,185
Allowance for equity funds during construction	**150**	17
Other income	**733**	767
Other deductions	**(770)**	(1,308)
Income tax expense	**(1,433)**	(1,425)
Total Other Income	**3,125**	2,236
Interest Expense		
Interest on long-term debt	**2,811**	1,937
Other interest	**119**	831
Allowance for borrowed funds during construction	**(54)**	(8)
Total Interest Expense	**2,876**	2,760
Net Income	**6,872**	5,908
Dividends declared on preferred stock	**92**	92
Earnings available for common stock	**$ 6,780**	$ 5,816
Per Common Share Data:		
Basic earnings per share	**$ 0.58**	$ 0.57
Diluted earnings per share	**$ 0.58**	$ 0.56
Average shares of common stock outstanding - basic	**11,602,354**	10,275,505
Average shares of common stock outstanding - diluted	**11,655,175**	10,377,034
Dividends declared per share of common stock	**$ 0.46**	$ 0.46

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(dollars in thousands)
(unaudited)

	Three months ended March 31	
	2009	2008
Net Income	**$ 6,872**	$ 5,908
Other comprehensive income, net of tax:		
Defined benefit pension and postretirement medical plans:		
Portion reclassified through amortizations, included in benefit costs and recognized in net income:		
Actuarial losses, net of income taxes of $0 and $0	**1**	1
Prior service cost, net of income taxes of $3 and $3	**3**	2
	4	3
Portion reclassified due to adoption of SFAS 158 measurement provision, included in retained earnings:		
Prior service cost, net of income taxes of $0 and $2	**0**	4
	0	4
Comprehensive income adjustments	**4**	**7**
Total comprehensive income	**$ 6,876**	$ 5,915

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(dollars in thousands, except share data)
(unaudited)

	March 31, 2009	December 31, 2008
ASSETS		
Utility plant		
Utility plant, at original cost	$ 571,858	$ 554,506
Less accumulated depreciation	248,328	244,219
Utility plant, at original cost, net of accumulated depreciation	323,530	310,287
Property under capital leases, net	5,901	6,133
Construction work-in-progress	14,340	24,632
Nuclear fuel, net	1,443	1,475
Total utility plant, net	345,214	342,527
Investments and other assets		
Investments in affiliates	104,158	102,232
Non-utility property, less accumulated depreciation ($3,663 in 2009 and $3,657 in 2008)	1,816	1,786
Millstone decommissioning trust fund	3,712	4,203
Other	5,395	5,469
Total investments and other assets	115,081	113,690
Current assets		
Cash and cash equivalents	13,544	6,722
Restricted cash	5,621	3,636
Special deposits	6	1,006
Accounts receivable, less allowance for uncollectible accounts ($2,522 in 2009 and $2,184 in 2008)	28,802	23,176
Accounts receivable - affiliates, less allowance for uncollectible accounts ($0 in 2009 and 2008)	78	76
Unbilled revenues	15,418	18,546
Materials and supplies, at average cost	6,088	6,299
Prepayments	6,958	17,367
Power-related derivatives	15,527	12,758
Other current assets	1,433	1,269
Total current assets	93,475	90,855
Deferred charges and other assets		
Regulatory assets	60,729	63,474
Other deferred charges - regulatory	8,769	9,980
Other deferred charges and other assets	4,228	5,467
Power-related derivatives	0	133
Total deferred charges and other assets	73,726	79,054
TOTAL ASSETS	$ 627,496	$ 626,126

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(dollars in thousands, except share data)
(unaudited)

	March 31, 2009	December 31, 2008
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common stock, $6 par value, 19,000,000 shares authorized, 13,811,970 issued and 11,648,948 outstanding at March 31, 2009 and 13,750,717 issued and 11,574,825 outstanding at December 31, 2008	**$ 82,872**	$ 82,504
Other paid-in capital	**71,552**	71,489
Accumulated other comprehensive loss	**(224)**	(228)
Treasury stock, at cost, 2,163,022 shares at March 31, 2009 and 2,175,892 shares at December 31, 2008	**(49,208)**	(49,501)
Retained earnings	**116,655**	115,215
Total common stock equity	**221,647**	219,479
Preferred and preference stock not subject to mandatory redemption	**8,054**	8,054
Preferred stock subject to mandatory redemption	**0**	1,000
Long-term debt	**167,500**	167,500
Capital lease obligations	**4,934**	5,173
Total capitalization	**402,135**	401,206
Current liabilities		
Current portion of preferred stock subject to mandatory redemption	**1,000**	1,000
Current portion of long-term debt	**5,450**	5,450
Accounts payable	**7,896**	3,549
Accounts payable - affiliates	**11,295**	11,338
Notes payable	**10,827**	10,800
Nuclear decommissioning costs	**1,363**	1,431
Power-related derivatives	**0**	2
Other current liabilities	**29,772**	33,645
Total current liabilities	**67,603**	67,215
Deferred credits and other liabilities		
Deferred income taxes	**42,889**	45,314
Deferred investment tax credits	**2,871**	2,962
Nuclear decommissioning costs	**8,232**	8,618
Asset retirement obligations	**3,353**	3,302
Accrued pension and benefit obligations	**52,145**	51,211
Power-related derivatives	**4,235**	4,069
Other deferred credits - regulatory	**20,179**	17,696
Other deferred credits and other liabilities	**23,854**	24,533
Total deferred credits and other liabilities	**157,758**	157,705
Commitments and contingencies		
TOTAL CAPITALIZATION AND LIABILITIES	**$ 627,496**	$ 626,126

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(dollars in thousands)
(unaudited)

	Three months ended March 31 2009	2008
OPERATING ACTIVITIES		
Net income	**$ 6,872**	$ 5,908
Adjustments to reconcile net income to net cash provided by operating activities:		
Equity in earnings of affiliates	**(4,445)**	(4,185)
Distributions received from affiliates	**2,519**	1,330
Depreciation	**4,029**	3,869
Deferred income taxes and investment tax credits	**(116)**	(200)
Regulatory and other amortization, net	**249**	149
Non-cash employee benefit plan costs	**1,597**	1,445
Other non-cash expense and (income), net	**1,617**	1,368
Changes in assets and liabilities:		
Increase in accounts receivable and unbilled revenues	**(3,082)**	(1,350)
Increase (decrease) in accounts payable	**4,245**	(2,052)
Decrease in prepaid income taxes	**10,619**	3,098
Decrease in other current assets	**203**	702
(Increase) decrease in special deposits and restricted cash for power collateral	**(1,985)**	62
Employee benefit plan funding	**(275)**	(586)
(Decrease) increase in other current liabilities	**(7,332)**	1,848
Increase (decrease) in other long-term liabilities and other	**413**	(184)
Net cash provided by operating activities	**15,128**	11,222
INVESTING ACTIVITIES		
Construction and plant expenditures	**(5,805)**	(7,267)
Investments in available-for-sale securities	**(316)**	(202)
Proceeds from sale of available-for-sale securities	**249**	135
Return of capital from investments in affiliates	**0**	96
Other investing activities	**(65)**	(44)
Net cash used by investing activities	**(5,937)**	(7,282)
FINANCING ACTIVITIES		
Proceeds from issuance of common stock	**687**	1,180
Retirement of preferred stock subject to mandatory redemption	**(1,000)**	(1,000)
Decrease in special deposits held for preferred stock redemptions	**1,000**	1,000
Common and preferred dividends paid	**(2,758)**	(2,453)
Proceeds from borrowings under revolving credit facility	**11,325**	9,300
Repayments under revolving credit facility	**(11,298)**	(9,300)
Common stock offering costs	**(54)**	0
Other financing activities	**(271)**	(105)
Net cash used by financing activities	**(2,369)**	(1,378)
Net increase in cash and cash equivalents	**6,822**	2,562
Cash and cash equivalents at beginning of the period	**6,722**	3,803
Cash and cash equivalents at end of the period	**$ 13,544**	$ 6,365

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN COMMON STOCK EQUITY
(in thousands, except share data)
(unaudited)

	Common Stock				Treasury Stock			
	Shares Issued	Amount	Other Paid-in Capital	Accumulated Other Comprehensive Loss	Share	Amount	Retained Earnings	Total
Balance, December 31, 2008	13,750,717	$ 82,504	$ 71,489	$ (228)	2,175,892	$ (49,501)	$ 115,215	$ 219,479
Net income							6,872	6,872
Other comprehensive income				4				4
Common Stock Issuance, net of issuance costs			(54)					(54)
Dividend reinvestment plan					(12,870)	293		293
Stock options exercised	36,160	217	284					501
Share-based compensation:								
Common & nonvested shares			1					1
Performance share plans	25,093	151	(187)					(36)
Dividends declared:								
Common - $0.46 per share							(5,337)	(5,337)
Cumulative non-redeemable preferred stock							(92)	(92)
Amortization of preferred stock issuance expense			3					3
Gain (Loss) on capital stock			16				(3)	13
Balance, March 31, 2009	13,811,970	$ 82,872	$ 71,552	$ (224)	2,163,022	$ (49,208)	$ 116,655	$ 221,647

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - BUSINESS ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General Description of Business Central Vermont Public Service Corporation ("we", "us", "CVPS" or the "company") is the largest electric utility in Vermont. We engage principally in the purchase, production, transmission, distribution and sale of electricity. We serve approximately 159,000 customers in 163 of the towns and cities in Vermont. Our Vermont utility operation is our core business. We typically generate most of our revenues through retail electricity sales. We also sell excess power, if any, to third parties in New England and to ISO-New England, the operator of the region's bulk power system and wholesale electricity markets. The resale revenue generated from these sales helps to mitigate our power supply costs.

Our wholly owned subsidiaries include Custom Investment Corporation, C.V. Realty, Inc., Central Vermont Public Service Corporation - East Barnet Hydroelectric, Inc. ("East Barnet") and Catamount Resources Corporation ("CRC"). We have equity ownership interests in Vermont Yankee Nuclear Power Corporation ("VYNPC"), Vermont Electric Power Company, Inc. ("VELCO"), Vermont Transco LLC ("Transco"), Maine Yankee Atomic Power Company ("Maine Yankee"), Connecticut Yankee Atomic Power Company ("Connecticut Yankee") and Yankee Atomic Electric Company ("Yankee Atomic").

Basis of Presentation These unaudited interim financial statements have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission. Accordingly, certain information and footnote disclosures normally included in the financial statements prepared in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") have been condensed or omitted. In our opinion, the accompanying interim financial statements reflect all normal, recurring adjustments considered necessary for a fair presentation. Operating results for the interim periods presented herein may not be indicative of the results that may be expected for the year. The financial statements incorporated herein should be read in conjunction with the consolidated financial statements and accompanying notes included in our annual report on Form 10-K for the year ended December 31, 2008.

Regulatory Accounting Our utility operations are regulated by the Vermont Public Service Board ("PSB"), the Connecticut Department of Public Utility and Control and the Federal Energy Regulatory Commission ("FERC"), with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. As such, we prepare our financial statements in accordance with SFAS 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS 71"). The application of SFAS 71 results in differences in the timing of recognition of certain expenses from those of other businesses and industries. In order for us to report our results under SFAS 71, our rates must be designed to recover our costs of providing service, and we must be able to collect those rates from customers. If rate recovery of these costs becomes unlikely or uncertain, whether due to competition or regulatory action, this accounting standard would no longer apply to our regulated operations. In the event we determine that our utility operations no longer meet the criteria for applying SFAS 71, the accounting impact would be an extraordinary non-cash charge to operations of an amount that would be material unless stranded cost recovery is allowed through a rate mechanism. Criteria that could give rise to the discontinuance of SFAS 71 include increasing competition that restricts a company's ability to establish prices to recover specific costs, and a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. Based on a current evaluation of the factors and conditions expected to impact future cost recovery, we believe future recovery of our regulatory assets is probable. See Note 4 - Retail Rates and Regulatory Accounting.

Derivative Financial Instruments We account for certain power contracts as derivatives under the provisions of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted and SFAS 149, *Amendment of Statement 133 Derivative Instruments and Hedging Activities*, (collectively "SFAS 133"). These statements require that derivatives be recorded on the balance sheet at fair value. Our derivative financial instruments are related to managing our power supply resources to serve our customers, and are not for trading purposes. We have determined that most of our forward power transactions do not qualify for the "normal" purchase and sale exception in SFAS 133. We have not yet evaluated a recent forward power purchase contract for this exception, and we are currently recording this contract as a derivative. Additionally, we have not elected hedge accounting for our power-related derivatives.

Based on a PSB-approved Accounting Order, we record unrealized gains and losses on all of our derivatives as deferred credits and deferred charges on the balance sheet. The corresponding derivative fair values are recorded as current and long-term assets or liabilities depending on the duration of the contracts. Realized gains and losses on sales are recorded as increases to or reductions of operating revenues, respectively. For purchase contracts, realized gains and losses are recorded as reductions of or additions to purchased power expense, respectively.

Our power-related derivatives include forward energy contracts, one long-term purchased power contract that allows the seller to repurchase specified amounts of power with advance notice ("Hydro-Quebec Sellback #3") and financial transmission rights. All of our power-related derivatives are commodity contracts. For additional information about power-related derivatives, see Note 5 - Fair Value and Note 6 - Power-Related Derivatives.

Recently Adopted Accounting Pronouncements

SFAS 141R: On January 1, 2009, we adopted SFAS No. 141 (revised 2007), *Business Combinations* ("SFAS 141R"). SFAS 141R replaces SFAS 141 and establishes principles and requirements for the recognition and measurement by acquirers of assets acquired, liabilities assumed, any noncontrolling interest in the acquiree and any goodwill acquired. SFAS 141R also establishes disclosure requirements to enable financial statement readers to evaluate the nature and financial effects of the business combination. The impact of applying SFAS 141R for periods subsequent to implementation will be dependent upon the nature of any transactions within the scope of SFAS 141R.

FSP FAS 157-2: On January 1, 2009, we adopted FASB Staff Position No. FAS 157-2, *Effective Date of FASB Statement No. 157* ("FSP FAS 157-2"). FSP FAS 157-2 identifies certain non-recurring fair value measures that are subject to the reporting requirements of SFAS No. 157, *Fair Value Measurements*, including asset retirement obligations ("AROs"). The provisions of FSP FAS 157-2 did not have an impact on our financial position, results of operations or cash flows. We are subject to expanded disclosure requirements when an ARO is initially recognized at fair value. See Note 5 - Fair Value for additional information.

SFAS 160: On January 1, 2009, we adopted SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51* ("SFAS 160"). SFAS 160 states that minority interests will be recharacterized as noncontrolling interests and classified as a component of equity. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. It requires that once a subsidiary is deconsolidated, any retained noncontrolling equity investment in the former subsidiary be initially measured at fair value. The provisions of SFAS 160 did not have an impact on our financial position, results of operations or cash flows.

SFAS 161: On January 1, 2009, we adopted FASB Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities-An Amendment of FASB Statement No. 133* ("SFAS 161"). SFAS 161 requires enhanced disclosures about an entity's derivative and hedging activities and applies to all entities. The provisions of SFAS 161 did not have an impact on our financial position, results of operations or cash flows. See Note 6 - Power-Related Derivatives for additional information.

Recent Accounting Pronouncements Not Yet Adopted

FSP FAS 157-4: In April 2009, the FASB issued FSP No. FAS 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly* ("FSP FAS 157-4"). We are currently evaluating this FSP; however, we do not expect that it will have a material impact on our financial position, results of operations or cash flows. The FSP will be effective for us as of June 30, 2009.

FSP FAS 115-2 and FAS 124-2: In April 2009, the FASB issued FSP No. FAS 115-2 and 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments* ("FSP FAS 115-2 and FAS 124-2"). We are currently evaluating this FSP; however, we do not expect that it will have a material impact on our financial position, results of operations or cash flows. The FSP will be effective for us as of June 30, 2009.

FSP FAS 107-1 and APB 28-1: In April 2009, the FASB issued FSP No. FAS 107-1 and APB 28-1, *Interim Disclosures About Fair Value of Financial Instruments* ("FSP FAS 107-1 and APB 28-1"). We do not believe the adoption of FSP FAS 107-1 and APB 28-1 will have a material impact on our consolidated financial statements since its requirements are limited to additional disclosures. The FSP will be effective for us as of June 30, 2009.

FSP FAS 132(R)-1: In December 2008, the FASB issued FSP No. FAS 132(R)-1, *Employers' Disclosures about Postretirement Benefit Plan Assets* ("FSP FAS 132(R)-1"), which requires additional disclosures for employers' pension and other postretirement benefit plan assets. Pension and postretirement medical benefit plan assets were not included within the scope of SFAS No. 157. FSP FAS 132(R)-1 requires employers to disclose information about fair value measurements of plan assets similar to the disclosures required under SFAS No. 157. Those disclosures will include the investment policies and strategies for the major categories of plan assets, and significant concentrations of risk within plan assets. We do not believe the adoption of FSP FAS 132(R)-1 will have a material impact on our consolidated financial statements since its requirements are limited to additional disclosures. The FSP will be effective for us as of December 31, 2009.

NOTE 2 - EARNINGS PER SHARE ("EPS")

The Condensed Consolidated Statements of Income include basic and diluted per share information. Basic EPS is calculated by dividing net income, after preferred dividends, by the weighted-average number of common shares outstanding for the period. Diluted EPS follows a similar calculation except that the weighted-average number of common shares is increased by the number of potentially dilutive common shares. The table below provides a reconciliation of the numerator and denominator used in calculating basic and diluted EPS for the three months ended March 31 (dollars in thousands, except share information):

	2009	2008
Numerator for basic and diluted EPS:		
Net income	**$ 6,872**	$ 5,908
Dividends declared on preferred stock	**(92)**	(92)
Net income available for common stock	**$ 6,780**	$ 5,816
Denominators for basic and diluted EPS:		
Weighted-average basic shares of common stock outstanding	**11,602,354**	10,275,505
Dilutive effect of stock options	**39,127**	90,916
Dilutive effect of performance shares	**13,694**	10,613
Weighted-average diluted shares of common stock outstanding	**11,655,175**	10,377,034

All outstanding stock options were included in the computation of diluted shares in the first quarter of 2009 and 2008 because the exercise prices were below the average market price of common shares. All performance shares were included in the computation in the first quarter of 2009. A total of 12,159 performance shares in the first quarter of 2008 were excluded from the computation because the grant-date fair value exceeded the average market price of common shares.

NOTE 3 - INVESTMENTS IN AFFILIATES

VELCO Summarized financial information for VELCO consolidated for the three months ended March 31 follows (dollars in thousands):

	2009	2008
Operating revenues	**$ 23,747**	$ 17,874
Operating income	**$ 12,315**	$ 8,609
Net income	**$ 9,963**	$ 8,339
Less net income attributable to non-controlling interests	**9,073**	7,628
Net income attributable to VELCO	**$ 890**	$ 711
Company's common stock ownership interest	**47.05%**	47.05%
Company's equity in net income	**$ 414**	$ 372

Accounts payable to VELCO were $5.4 million at March 31, 2009 and $5.6 million at December 31, 2008.

Transco Summarized financial information for Transco, also included in VELCO consolidated financial information above, for the three months ended March 31, follows (dollars in thousands):

		2009		2008
Operating revenues	$	23,621	$	17,747
Operating income	$	12,998	$	9,058
Net income	$	10,733	$	8,767
Company's ownership interest		33.02%		39.79%
Company's equity in net income	$	3,968	$	3,732

Transmission services provided by Transco are billed to us under the 1991 Transmission Agreement ("VTA"). All Vermont electric utilities are parties to the VTA. This agreement requires the Vermont utilities to pay their pro rata share of Transco's total costs, including interest and a fixed rate of return on equity, less the revenue collected under the ISO-New England Open Access Transmission Tariff and other agreements.

Transco's billings to us primarily include the VTA and charges and reimbursements under the NEPOOL Open Access Transmission Tariff ("NOATT"). Included in Transco's operating revenues above are transmission services to us amounting to $2.5 million in the first quarter of 2009 and $3.4 million in the first quarter of 2008. These amounts are reflected as Transmission - affiliates on our condensed consolidated statements of income. Accounts payable to Transco were $0.6 million at March 31, 2009 and $0.4 million at December 31, 2008.

VYNPC Summarized financial information for VYNPC for the three months ended March 31 follows (dollars in thousands):

		2009		2008
Operating revenues	$	44,771	$	45,654
Operating (loss) income	$	(974)	$	139
Net income	$	94	$	124
Company's common stock ownership interest		58.85%		58.85%
Company's equity in net income	$	56	$	73

Included in VYNPC's operating revenues above are sales to us of approximately $15.7 million in the first quarter of 2009 and $15.9 million in the first quarter of 2008. These are included in Purchased power - affiliates on our condensed consolidated statements of income. Accounts payable to VYNPC were $5.2 million at March 31, 2009 and $5.3 million at December 31, 2008. Also see Note 8 - Commitments and Contingencies.

Maine Yankee, Connecticut Yankee and Yankee Atomic We own, through equity investments, 2 percent of Maine Yankee, 2 percent of Connecticut Yankee and 3.5 percent of Yankee Atomic. All three companies have completed plant decommissioning and the operating licenses have been amended by the Nuclear Regulatory Commission ("NRC") for operation of Independent Spent Fuel Storage Installations. All three remain responsible for safe storage of the spent nuclear fuel and waste at the sites until the United States Department of Energy ("DOE") meets its obligation to remove the material from the sites. Our share of the companies' estimated costs are reflected on the Condensed Consolidated Balance Sheets as regulatory assets and nuclear decommissioning liabilities (current and non-current). These amounts are adjusted when revised estimates are provided. At March 31, 2009, we had regulatory assets of $1.2 million for Maine Yankee, $6 million for Connecticut Yankee and $2.4 million for Yankee Atomic. These estimated costs are being collected from customers through existing retail rate tariffs. Total billings from the three companies amounted to $0.3 million in the first quarter of 2009 and $0.6 million in the first quarter of 2008. These amounts are included in Purchased power - affiliates on our Condensed Consolidated Statements of income.

All three companies have been seeking recovery of fuel storage-related costs stemming from the default of the DOE under the 1983 fuel disposal contracts that were mandated by the United States Congress under the Nuclear Waste Policy Act of 1982. Under the Act, the companies believe the DOE was required to begin removing spent nuclear fuel and Greater than Class C material from the nuclear plants no later than January 31, 1998 in return for payments by each company into the nuclear waste fund. No fuel has been collected by the DOE, and each company's spent fuel is stored at its own site. Maine Yankee, Connecticut Yankee and Yankee Atomic collected the funds from us and other wholesale utility customers, under FERC-approved wholesale rates, and our share of these payments was collected from our retail customers.

In 2006, the United States Court of Federal Claims issued judgment in the spent fuel litigation. Maine Yankee was awarded $75.8 million in damages through 2002, Connecticut Yankee was awarded $34.2 million through 2001 and Yankee Atomic was awarded $32.9 million through 2001. In December 2006, the DOE filed a notice of appeal of the court's decision and all three companies filed notices of cross appeals. In August 2008, the United States Court of Appeals for the Federal Circuit reversed the award of damages and remanded the cases back to the trial courts. The remand directed the trial courts to apply the acceptance rate in 1987 annual capacity reports when determining damages. In January 2009, the United State Court of Federal Claims issued an order reserving weeks in August 2009 for the pre-trial conference, trial and any other proceedings necessary for final resolution of this issue.

On March 6, 2009, the three companies submitted their statement of claimed damages on remand. Maine Yankee claimed $81.7 million, Connecticut Yankee claimed $39.7 million and Yankee Atomic claimed $53.9 million in damages through 2001. Our share of the claimed damages is based on our ownership percentages described above.

Due to the complexity of the issues and the potential for further appeals, the three companies cannot predict the timing of the final determination or the amount of damages that will actually be received. Each of the companies' respective FERC settlements requires that damage payments, net of taxes and further spent fuel trust funding, if any, be credited to wholesale ratepayers including us. We expect that our share of these awards, if any, would be credited to our retail customers.

The Court of Appeal's original decision, if maintained on remand, established the DOE's responsibility for reimbursing Maine Yankee for its actual costs through 2002 and Connecticut Yankee and Yankee Atomic for their actual costs through 2001 related to the incremental spent fuel storage, security, construction and other costs of the spent fuel storage installation. Although the decision did not resolve the question regarding damages in subsequent years, the decision did support future claims for the remaining spent fuel storage installation construction costs. In December 2007, Maine Yankee, Connecticut Yankee and Yankee Atomic filed a second round of claims against the government for damages sustained since January 1, 2002 for Connecticut Yankee and Yankee Atomic, and since January 1, 2003 for Maine Yankee. We cannot predict the ultimate outcome of these cases due to the pending remand and potential for subsequent appeals and the complexity of the issues in the second round of cases.

NOTE 4 - RETAIL RATES AND REGULATORY ACCOUNTING

Retail Rates Our retail rates are approved by the PSB after considering the recommendations of Vermont's consumer advocate, the Vermont Department of Public Service ("DPS"). Fair regulatory treatment is fundamental to maintaining our 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 return on common equity of our regulated business did not exceed the allowed return for 2008.

On September 30, 2008, the PSB issued an order approving, with modifications, the alternative regulation plan proposal that we submitted in August 2007. The plan became effective on November 1, 2008. It expires on December 31, 2011, but we have an option to petition for an extension beyond 2011. The plan replaces the traditional ratemaking process and allows for quarterly rate adjustments to reflect changes in power supply and transmission-by-others costs ("PCAM adjustment"); annual base rate adjustments to reflect changing costs; and annual rate adjustments to reflect changes, within predetermined limits, from the allowed earnings level. Under the plan, the allowed return on equity will be adjusted annually to reflect one-half of the change in the yield on the 10-year Treasury note as measured over the last 20 trading days prior to October 15 of each year. The earnings sharing adjustment mechanism ("ESAM") within the plan provides for the return on equity of the regulated portion of our business to fall between 75 basis points above or below the allowed return on equity before any adjustment is made. If the actual return on equity of the regulated portion of our business exceeds 75 basis points above the allowed return, the excess amount is returned to ratepayers in a future period. If the actual return on equity of our regulated business falls between 75 and 100 basis points below the allowed return on equity, the shortfall is shared equally between shareholders and ratepayers. Any earnings shortfall in excess of 100 basis points below the allowed return on equity is recovered from ratepayers. These adjustments are made at the end of each fiscal year.

The PCAM adjustment and the ESAM are not subject to PSB suspension, but the PSB may open an investigation and to the extent it finds, after notice and hearing, that the calculation was inaccurate or reflects costs inappropriate for inclusion in rates, it may require a modification of the of the associated adjustments to the extent necessary to correct the deficiencies.

On October 31, 2008, we submitted a base rate filing for the rate year commencing January 1, 2009 that reflected a 0.33 percent increase in retail rates. The result of the return on equity adjustment for 2009, in accordance with the plan, was a reduction of 0.44 percent, resulting in an allowed return on equity for 2009 of 9.77 percent. On November 17, 2008, the DPS filed a request for suspension and investigation of our filing. Citing concerns about staffing levels and inadequate supporting documentation for some proposed plant additions, the DPS recommended a 0.43 percent rate decrease.

On December 17, 2008, we filed a Memorandum of Understanding with the PSB setting forth agreements that we reached with the DPS regarding the PSB's investigation into our 2009 retail rates. Pursuant to the Memorandum of Understanding, we agreed to leave rates unchanged, with no increase or decrease, and that we and the DPS would request the PSB to open a docket to resolve the DPS's concerns regarding our level of staffing. On February 13, 2009, the PSB approved the Memorandum of Understanding, and ordered the rate investigation closed.

On February 2, 2009, we filed a motion with the PSB requesting to defer the incremental 2008 storm costs through our alternative regulation plan and collect through the ESAM over 12 months beginning on July 1, 2009. On February 3, 2009, the DPS filed a letter supporting our motion and on February 12, 2009, the PSB approved the request. The amount of the deferral, based on actual costs, was $3.2 million.

The first quarter 2009 PCAM adjustment was calculated to be an over collection of $0.6 million and was recorded as a regulatory liability. The over collection will be returned to customers over three months beginning July 1, 2009.

On February 13, 2009, the PSB opened an investigation into the staffing levels of the company as requested by us and the DPS. On March 25, 2009, the PSB convened a prehearing conference where we and the DPS agreed to a procedural schedule, and technical hearings are scheduled for June 2009. We and the DPS further agreed that the scope of the technical hearings could be narrowed to devising a methodology for deriving productivity measures that would be tracked over time. The parties do not agree, however, as to what the substantive elements of that tracking methodology should be. Accordingly, the PSB ordered that the purpose of hearings in this proceeding will be to resolve this disagreement about the makeup of the productivity tracking methodology.

Regulatory Accounting Under SFAS 71, we account for certain transactions in accordance with permitted regulatory treatment whereby regulators may permit incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when recovered through future revenues. In the event that we no longer meet the criteria under SFAS 71 and there is not a rate mechanism to recover these costs, we would be required to write off $16.2 million of regulatory assets (total regulatory assets of $60.7 million less pension and postretirement medical costs of $44.5 million), $8.8 million of other deferred charges - regulatory and $20.2 million of other deferred credits - regulatory. This would result in a total extraordinary charge to operations of $4.8 million on a pre-tax basis as of March 31, 2009. We would be required to record pre-tax pension and postretirement costs of $43.6 million to Accumulated Other Comprehensive Loss and $0.9 million to Retained Earnings as reductions to stockholders' equity. We would also be required to determine any potential impairment to the carrying costs of deregulated plant.

All regulatory assets are being recovered in retail rates and are earning a return except for income taxes, nuclear plant dismantling costs and pension and postretirement medical costs. Regulatory assets, certain other deferred charges and other deferred credits are shown in the table below (dollars in thousands).

	March 31, 2009	December 31, 2008
Regulatory assets		
Pension and postretirement medical costs - SFAS 158	**$ 44,462**	$ 46,911
Nuclear plant dismantling costs	**$ 9,594**	10,049
Nuclear refueling outage costs - Millstone Unit #3	**$ 1,077**	1,347
Income taxes	**$ 4,212**	4,115
Asset retirement obligations and other	**$ 1,384**	1,052
Total Regulatory assets	**$ 60,729**	63,474
Other deferred charges - regulatory		
Vermont Yankee sale costs (tax)	**673**	673
Deferral of December 2008 storm costs	**3,235**	4,059
Unrealized losses on power-related derivatives	**4,235**	4,070
Other	**626**	1,178
Total Other deferred charges - regulatory	**8,769**	9,980
Other deferred credits - regulatory		
Asset retirement obligation - Millstone Unit #3	**967**	1,497
Vermont Yankee settlements	**638**	789
Emission allowances and renewable energy credits	**231**	308
Unrealized gains on power-related derivatives	**15,424**	12,756
Environmental remediation	**750**	1,000
PCAM adjustment	**578**	0
Other	**1,591**	1,346
Total Other deferred credits - regulatory	**$ 20,179**	$ 17,696

NOTE 5 - FAIR VALUE

Effective January 1, 2008, we adopted SFAS 157 as required. SFAS 157 establishes a single, authoritative definition of fair value, prescribes methods for measuring fair value, establishes a fair value hierarchy based on the inputs used to measure fair value and expands disclosures about the use of fair value measurements; however, SFAS 157 does not expand the use of fair value accounting in any new circumstances. SFAS 157 defines 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.”

Fair Value Hierarchy SFAS 157 establishes a fair value hierarchy (“hierarchy”) to prioritize the inputs used in valuation techniques. The hierarchy is designed to indicate the relative reliability of the fair value measure. The highest priority is given to quoted prices in active markets, and the lowest to unobservable data, such as an entity’s internal information. The lower the level of the input of a fair value measurement, the more extensive the disclosure requirements. There are three broad levels:

Level 1: Quoted prices (unadjusted) are available in active markets for identical assets or liabilities as of the reporting date. Level 1 includes cash equivalents that consist of money market funds.

Level 2: Pricing inputs are other than quoted prices in active markets included in Level 1, which are directly or indirectly observable as of the reporting date. This value is based on other observable inputs, including quoted prices for similar assets and liabilities in markets that are not active. Level 2 includes investments in our Millstone Decommissioning Trust Funds such as fixed income securities (Treasury securities, other agency and corporate debt) and equity securities.

Level 3: Pricing inputs include significant inputs that are generally less observable. Unobservable inputs may be used to measure the asset or liability where observable inputs are not available. We develop these inputs based on the best information available, including our own data. Level 3 recurring fair value measurements include derivatives related to our forward energy purchases and sales, financial transmission rights and a power-related option contract.

Recurring Measures The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that are accounted for at fair value on a recurring basis. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels (dollars in thousands):

	Fair Value as of March 31, 2009			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Millstone decommissioning trust fund	$ 0	$ 3,712	$ 0	$ 3,712
Cash equivalents	10,990	0	0	10,990
Restricted cash	5,621	0	0	5,621
Power-related derivatives - current	0	0	15,527	15,527
Total	$ 16,611	$ 3,712	$ 15,527	$ 35,850
Liabilities:				
Power-related derivatives - current	$ 0	$ 0	$ 0	$ 0
Power-related derivatives - long term	0	0	4,235	4,235
Total	$ 0	$ 0	$ 4,235	$ 4,235

	Fair Value as of December 31, 2008			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Millstone decommissioning trust fund	$ 0	$ 4,203	$ 0	$ 4,203
Cash equivalents	5,028	0	0	5,028
Restricted cash	3,636	0	0	3,636
Power-related derivatives - current	0	0	12,758	12,758
Power-related derivatives - long term	0	0	133	133
Total	$ 8,664	$ 4,203	$ 12,891	$ 25,758
Liabilities:				
Power-related derivatives - current	$ 0	$ 0	$ 2	$ 2
Power-related derivatives - long term	0	0	4,069	4,069
Total	$ 0	$ 0	$ 4,071	$ 4,071

Derivative Financial Instruments: We estimate fair values of power-related derivatives based on the best market information available, including the use of internally developed models and broker quotes for forward energy contracts. During interim periods, we use other models and our own assumptions about future congestion costs for valuing the remaining portion of annual financial transmission rights ("FTRs"). We use auction clearing prices from the monthly auctions held by ISO New England for valuing our month-ahead FTRs. At the end of each year, we use ISO New England's auction clearing prices to value all FTRs. We also use a binomial tree model and an internally developed long-term price forecast to value a power-related option contract.

Level 3 Reconciliation for Recurring Fair Value Measurements The following table is a reconciliation of changes in the net fair value of power-related derivatives which are classified as Level 3 in the fair value hierarchy. There were no transfers into or out of Level 3 during the periods presented (dollars in thousands).

	2009	2008
Power-related Derivatives, net		
Balance as of January 1	**$ 8,820**	$ (7,110)
Gains and losses (realized and unrealized)		
Included in earnings	**4,794**	(549)
Included in Regulatory and other assets/liabilities	**2,504**	(4,296)
Purchases, sales, issuances and net settlements	**(4,826)**	529
Balance as of March 31	**$ 11,292**	$ (11,426)

During the three months ended March 31, 2009 and 2008, there were no realized gains or losses included in earnings attributable to the change in unrealized gains or losses related to derivatives still held at the reporting date. This is due to our regulatory accounting treatment for all power-related derivatives.

Based on a PSB-approved Accounting Order, we record the change in fair value of power contract derivatives as deferred charges or deferred credits on the Condensed Consolidated Balance Sheet, depending on whether the derivatives are assets or liabilities. For all derivative assets except FTRs, we record offsetting deferred credits which represent unrealized gains. For FTR derivatives which are purchased from ISO New England in periodic auctions, we record the fair value as derivative assets or liabilities and we record a related account payable representing the amount to be paid for the FTR. The difference between the FTR's fair value and the account payable balance is recorded as a deferred charge or deferred credit which represents an unrealized loss or gain on the FTR. For other derivative liabilities, we record an offsetting deferred charge which represents unrealized losses. Derivative fair values are recorded as current and long-term assets or liabilities depending on their duration. For additional information on power contract derivatives, see Note 6 - Power-Related Derivatives.

Non-Recurring Measures-Asset Retirement Obligations: On January 1, 2009 we adopted FASB Staff Position No. FAS 157-2, *Effective Date of FASB Statement No. 157* ("FSP 157-2"). FSP 157-2 identifies certain non-recurring fair value measures which are subject to the reporting requirements of SFAS 157, including AROs. AROs are recognized for items that can be reasonably estimated such as asbestos removal, disposal of polychlorinated biphenyls in certain transformers and breakers, and mercury in batteries and certain meters. During the quarter ended March 31, 2009, there were no fair value measurements relating to AROs.

NOTE 6 - POWER-RELATED DERIVATIVES

We are exposed to certain risks relating to managing our power supply resources to serve our customers, and we use derivative financial instruments to manage those risks. The primary risk managed by using derivative financial instruments is commodity price risk. Currently, our power supply forecast shows energy purchase and production amounts in excess of our load requirements through 2011. Because of this projected power surplus, we have entered into forward power sale contracts to reduce price volatility of our net power costs. On occasion, we will forecast a temporary power supply shortage such as when Vermont Yankee becomes unavailable. We typically enter into short-term forward power purchase contracts to cover a portion of these expected power supply shortages, which helps to reduce price volatility in our net power costs. Beginning in 2012, our power supply forecast shows that our load requirements will exceed our energy purchase and production amounts, as certain committed long-term power purchase contracts begin to expire. During the first quarter of 2009, we entered into one long-term forward power purchase contract for physical deliveries that are scheduled to occur between 2013 and 2015. Several years ago, we entered into a long-term purchased power contract that allows the seller to repurchase specified amounts of power with advance notice ("Hydro-Quebec Sellback #3"). In addition, we are able to economically hedge our exposure to congestion charges that result from constraints on the transmission system with FTRs. FTRs are awarded to the successful bidders in periodic auctions administered by ISO New England. We do not use derivative financial instruments for trading or other purposes.

Accounting for power-related derivatives is discussed in Note 1- Business Organization and Summary of Significant Accounting Policies - Derivative Financial Instruments.

As of March 31, 2009, we had the following outstanding commodity forward contracts:

Commodity	mWh (000s)
Forward Energy Sales	404.7
Forward Energy Purchase	394.2
Financial Transmission Rights	1,176.3
Hydro-Quebec Sellback #3	438.0

We recognized the following amounts in the Condensed Consolidated Statements of Income in connection with derivative financial instruments for the three months ended March 31 (dollars in thousands):

	2009	2008
Net realized gains (losses) reported in operating revenues	**$ 4,812**	$ (505)
Net realized gains (losses) reported in purchased power	**$ (18)**	$ (44)

For information on the location and amounts of derivative fair values on the Condensed Consolidated Balance Sheets see Note 5 - Fair Value.

Certain of our power-related derivative instruments contain provisions for performance assurance that may include the posting of collateral in the form of cash or letters of credit, or other credit enhancements. Our counterparties will typically establish collateral thresholds that represent credit limits, and these credit limits vary depending on our credit rating. If our current credit rating were to decline, certain counterparties could request immediate payment and full overnight ongoing collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on March 31, 2009, is $0.9 million for which we were not required to post collateral in the normal course of business. If the credit-risk-related contingent feature under this agreement was triggered on March 31, 2009, including a downgrade of our credit rating, we would be required to post an additional $0.9 million of collateral to our counterparty, upon request. For information concerning performance assurance that has already been posted as collateral, see Note 8 - Commitments and Contingencies - Performance Assurance.

NOTE 7 - PENSION AND POSTRETIREMENT MEDICAL BENEFITS

Components of net periodic benefit costs for the three months ended March 31 follow (dollars in thousands):

	Pension Benefits		Postretirement Benefits	
	2009	2008	**2009**	2008
Service cost	**$ 946**	$ 823	**$ 178**	$ 155
Interest cost	**1,652**	1,523	**428**	403
Expected return on plan assets	**(2,077)**	(1,831)	**(196)**	(267)
Amortization of net actuarial loss	**86**	0	**70**	263
Amortization of prior service cost	**0**	97	**379**	0
Amortization of transition obligation	**0**	0	**64**	64
Net periodic benefit cost	**607**	612	**923**	618
Less amounts capitalized	**68**	88	**102**	89
Net benefit costs expensed	**$ 539**	$ 524	**$ 821**	$ 529

Investment Strategy Our investment policy seeks to achieve sufficient growth to enable the plans to meet our future benefit obligations to participants, to maintain certain funded ratios and minimize near-term cost volatility. Current guidelines specify generally that 61 percent of plan assets be invested in equity securities and 39 percent of plan assets be invested in fixed income securities. The fixed-income assets are invested in longer-duration bonds to match changes in plan liabilities.

NOTE 8 - COMMITMENTS AND CONTINGENCIES

Long-Term Power Purchase Obligations *Vermont Yankee:* We are purchasing our entitlement share of Vermont Yankee plant output through the PPA between Entergy-Vermont Yankee and VYNPC. One remaining secondary purchaser continues to receive less than 0.5 percent of our entitlement. VYNPC's entitlement to plant output is 83 percent and our percentage share of plant output is 29 percent; our nominal entitlement is approximately 180 MW. Entergy-Vermont Yankee has no obligation to supply energy to VYNPC over its entitlement share of plant output, so we receive reduced amounts when the plant is operating at a reduced level, and no energy when the plant is not operating. The next scheduled refueling outage will be in 2010. Our total purchases from Vermont Yankee were $15.7 million in the first quarter of 2009 and $15.9 million in the first quarter of 2008.

We have a forced outage insurance policy to cover additional costs, if any, of obtaining replacement power from other sources if the Vermont Yankee plant experiences unplanned outages. The current policy covers the period March 22, 2009 through March 21, 2010. This outage insurance does not apply to reductions in production levels at the plant (referred to as a "derate") or acts of terrorism. The coverage applies to unplanned outages of up to 90 consecutive calendar days per outage event, and provides for payment of the difference between the spot market price and $42/mWh. The aggregate maximum coverage is $9 million with a $1.2 million deductible.

In July 2008, the Vermont Yankee plant experienced a 12-day derate, reaching a low of approximately 17 percent capacity during some of that time. The derate resulted from issues related to the plant's cooling towers. The incremental cost of the replacement power that we purchased during that time was approximately $1.1 million. We also lost approximately $1.1 million in resale sales revenue during that time. We were able to apply approximately $0.1 million as a reduction in purchased power expense from a regulatory liability established for the difference in the premium we paid for Vermont Yankee forced outage insurance and amounts currently collected in retail rates.

In the third quarter of 2007, the Vermont Yankee plant experienced a derate, after the collapse of a cooling tower at the plant, and a two-day unplanned outage associated with a valve failure. We purchased replacement energy adequate to meet most of our hourly load obligations during that period. The derate and unplanned outage increased our net power costs by about $1.3 million in the third quarter of 2007 through increased purchased power expense and decreased operating revenues due to reduced resale sales. We were also able to apply $0.3 million as reduction in purchased power expense from the regulatory liability.

We are considering whether to seek recovery of the incremental costs from Entergy-Vermont Yankee under the terms of the PPA based upon the results of certain reports, including a recent NRC inspection, in which the inspection team found that Entergy-Vermont Yankee, among other things, did not have sufficient design documentation available to help it prevent problems with the cooling towers. The NRC released its findings on October 14, 2008. In considering whether or not to seek recovery, we are also reviewing the 2007 and 2008 root cause analysis reports by Entergy as well as the December 22, 2008 reliability assessment provided by the Nuclear Safety Associates to the State of Vermont. We cannot predict the outcome of this matter at this time.

The PPA between Entergy-Vermont Yankee and VYNPC contains a formula for determining the VYNPC power entitlement following a 20 percent uprate in 2006. VYNPC and Entergy-Vermont Yankee are seeking to resolve certain differences in the interpretation of the formula. At issue is how much capacity and energy VYNPC Sponsors receive under the PPA following the uprate. Based on VYNPC's calculations the VYNPC Sponsors should be entitled to slightly more capacity and energy than they are currently receiving under the PPA. We cannot predict the outcome of this matter at this time.

If the Vermont Yankee plant is shut down for any reason prior to the end of its operating license, we would lose the economic benefit of an energy volume equal to close to 50 percent of our total committed supply and have to acquire replacement power resources for approximately 40 percent of our estimated power supply needs. Based on projected market prices as of March 31, 2009, the incremental replacement cost of lost power, including capacity, is estimated to average $27.3 million annually. We are not able to predict whether there will be an early shutdown of the Vermont Yankee plant. However, an early shutdown could materially impact our financial position and future results of operations if the costs are not recovered in retail rates in a timely fashion. The PCAM adjustment within our alternative regulation plan will allow more timely recovery of power costs in 2009, 2010 and 2011.

Hydro-Quebec: We are purchasing power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract. The VJO Power Contract has been in place since 1987 and purchases began in 1990. Related contracts were subsequently negotiated between us and Hydro-Quebec, altering the terms and conditions contained in the original contract by reducing the overall power requirements and related costs. The VJO contract runs through 2020, but our purchases under the contract end in 2016. The average level of deliveries decreases by approximately 20 percent to 30 percent after 2012, and by approximately 85 percent after 2015. Our total purchases under the VJO contract were $17.1 million in the first quarter of 2009 and $16.4 million in the first quarter of 2008.

Under the VJO Power Contract, the VJO had elections to change the annual load factor from 75 percent to between 70 and 80 percent five times through 2020, while Hydro-Quebec had elections to reduce the load factor to not less than 65 percent three times during the same period. Hydro-Quebec and the VJO have used all of their elections; therefore, the annual load factor is 75 percent for the remainder of the contract, unless the contract is changed or there is a reduction due to the adverse hydraulic conditions described below.

In the early phase of the VJO Power Contract, two sellback contracts were negotiated, the first delaying the purchase of 25 MW of capacity and associated energy, the second reducing the net purchase of Hydro-Quebec power through 1996. In 1994, we negotiated a third sellback arrangement whereby we received a reduction in capacity costs from 1995 to 1999. In exchange, Hydro-Quebec obtained two options. The first gives Hydro-Quebec the right, upon four years' written notice, to reduce capacity and associated energy deliveries by 50 MW, including the use of a like amount of our Phase I/II transmission facility rights. The second gives Hydro-Quebec the right, upon one year's written notice, to curtail energy deliveries in a contract year (12 months beginning November 1) from an annual capacity factor of 75 to 50 percent due to adverse hydraulic conditions as measured at certain metering stations on unregulated rivers in Quebec. This second option can be exercised five times through October 2015. To date, Hydro-Quebec has not exercised these options. We have determined that the first option is a derivative, but the second is not because it is contingent upon a physical variable.

There are specific contractual provisions providing that in the event any VJO member fails to meet its obligation under the contract with Hydro-Quebec, the remaining VJO participants, will "step-up" to the defaulting party's share on a pro-rata basis. As of March 31, 2009, our obligation is about 47 percent of the total VJO Power Contract through 2016, which represents approximately $404.4 million, on a nominal basis.

In accordance with FASB Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* ("FIN 45"), we are required to disclose the "maximum potential amount of future payments (undiscounted) the guarantor could be required to make under the guarantee." Such disclosure is required even if the likelihood is remote. With regard to the "step-up" provision in the VJO Power Contract, we must assume that all members of the VJO simultaneously default in order to estimate the "maximum potential" amount of future payments. We believe this is a highly unlikely scenario given that the majority of VJO members are regulated utilities with regulated cost recovery. Each VJO participant has received regulatory approval to recover the cost of this purchased power in their most recent rate applications. Despite the remote chance that such an event could occur, we estimate that our undiscounted purchase obligation would be about an additional $473 million for the remainder of the contract, assuming that all members of the VJO defaulted by April 1, 2009 and remained in default for the duration of the contract. In such a scenario, we would then own the power and could seek to recover our costs from the defaulting members or our retail customers, or resell the power in the wholesale power markets in New England. The range of outcomes (full cost recovery, potential loss or potential profit) would be highly dependent on Vermont regulation and wholesale market prices at the time.

Independent Power Producers: We receive power from several Independent Power Producers ("IPPs"). These plants use water and biomass as fuel. Most of the power comes through a state-appointed purchasing agent that allocates power to all Vermont utilities under PSB rules. In the first quarter of 2009, we purchased 47,952 mWh from IPPs at an average price of 12.3 cents per kWh, for a total cost of $5.9 million. This compares to 56,306 mWh at an average price of 14 cents per kWh, for a total cost of $7.9 million in the first quarter of 2008.

Nuclear Decommissioning Obligations We are obligated to pay our share of nuclear decommissioning costs for nuclear plants in which we have an ownership interest. We have an external trust dedicated to funding our joint-ownership share of future decommissioning costs. DNC has suspended contributions to the Millstone Unit #3 Trust Fund because the minimum NRC funding requirements are being met or exceeded. We have also suspended contributions to the Trust Fund, but could choose to renew funding at our own discretion as long as the minimum requirement is met or exceeded. If a need for additional decommissioning funding becomes necessary, we will be obligated to resume contributions to the Trust Fund.

We have equity ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. These plants are permanently shut down. Our obligations related to these plants are described in Note 3 - Investments in Affiliates.

We had a 35 percent ownership interest in the Vermont Yankee nuclear power plant but the plant was sold in 2002. VYNPC's obligation for plant decommissioning costs ended when the plant was sold. Per PSB order at the time of the sale approval, excess decommissioning funds, if any, will be returned to VYNPC sponsors and must be applied to the benefit of retail consumers. VYNPC retained responsibility for the pre-1983 spent fuel disposal cost liability. VYNPC has a dedicated Trust Fund that meets most of this spent fuel liability.

Performance Assurance We are subject to performance assurance requirements through ISO-New England under the Financial Assurance Policy of the FERC-approved tariff for NEPOOL members. We are required to post collateral for all net purchased power transactions since our credit limit with ISO-New England is zero. Additionally, we are currently selling power in the wholesale market pursuant to contracts with third parties, and are required to post collateral under certain conditions defined in the contracts.

At March 31, 2009, we had posted $8.1 million of collateral under performance assurance requirements for ISO-New England and certain third party power contracts, of which $2.5 million was in cash and $5.6 million was represented by restricted cash. At December 31, 2008, we had posted $6.9 million of collateral under performance assurance requirements for certain power contracts, of which $3.3 million was in cash and $3.6 million was represented by restricted cash.

We are also subject to performance assurance requirements under our Vermont Yankee power purchase contract (the 2001 Amendatory Agreement). If Entergy-Vermont Yankee, the seller, has commercially reasonable grounds to question our ability to pay for our monthly power purchases, Entergy-Vermont Yankee may ask VYNPC and VYNPC may then ask us to provide adequate financial assurance of payment. We have not had to post collateral under this contract.

Operating leases Prior to October 24, 2008, we leased our vehicles and related equipment under a single operating lease agreement. The individual leases under this agreement were mutually cancelable one year from lease inception. On November 14, 2008, we received notification from the lessor that this operating lease agreement was being terminated. Under the terms of the lease, we will be required to terminate all agreements under this lease by November 14, 2009 and pay the unamortized value of the equipment upon termination either by purchasing the equipment or through the sale of the equipment to a third party. At March 31, 2009, the unamortized value is $7.7 million.

On October 24, 2008, we entered into a second operating lease for vehicles and other related equipment with a different lessor. The lease schedules under this agreement are non-cancellable. At the end of the lease term, the lessor is entitled to recover a termination rental adjustment equal to 20 percent of the acquisition cost of the equipment. This payment can be recovered from us or through disposition of the equipment. In the case of disposition for less than 20 percent of the acquisition cost, our guarantee obligation is limited to 5 percent of the acquisition cost. If the entire lease portfolio had a fair value of zero at March 31, 2009, we would have been responsible for a maximum reimbursement of $2.2 million. The maximum amount available for lease under this agreement is currently $4 million, of which $2.3 million was outstanding at March 31, 2009.   At December 31, 2008, the maximum amount available for lease under this agreement was $4 million, of which $2.3 million was outstanding.

Other operating lease commitments are considered minimal, as most are cancelable after one year from inception or the future minimum lease payments are of a nominal amount.

Environmental Over the years, more than 100 companies have merged into or been acquired by CVPS. At least two of those companies used coal to produce gas for retail sale. Gas manufacturers, their predecessors and CVPS used waste disposal methods that were legal and acceptable then, but may not meet modern environmental standards and could represent a liability. These practices ended more than 50 years ago. Some operations and activities are inspected and supervised by federal and state authorities, including the Environmental Protection Agency. We believe that we are in compliance with all laws and regulations and have implemented procedures and controls to assess and assure compliance. Corrective action is taken when necessary. Below is a brief discussion of the sites for which we have recorded reserves.

Cleveland Avenue Property: The Cleveland Avenue property in Rutland, Vermont, was used by a predecessor to make gas from coal. Later, we sited various operations there. Due to the existence of coal tar deposits, polychlorinated biphenyl contamination and the potential for off-site migration, we conducted studies in the late 1980s and early 1990s to quantify the potential costs to remediate the site. Investigation at the site has continued, including work with the State of Vermont to develop a mutually acceptable solution. In 2008, we reviewed our reserve for this site based on a 2006 cost estimate of remediation and determined that it was adequate. The liability for site remediation is expected to range from $0.9 million to $2.3 million. As of March 31, 2009, we have accrued $1.1 million representing the most likely remaining cost of the remediation effort.

Brattleboro Manufactured Gas Facility: In the 1940s, we owned and operated a manufactured gas facility in Brattleboro, Vermont. We ordered a site assessment in 1999 at the request of the State of New Hampshire. In 2001, New Hampshire indicated that no further action was required, though it reserved the right to require further investigation or remedial measures. In 2002, the Vermont Agency of Natural Resources notified us that our corrective action plan for the site was approved. That plan is now in place. In 2008, we reviewed our reserve for this site based on a 2006 cost estimate of remediation and determined that it was adequate. The liability for site remediation is expected to range from $0.1 million to $1.3 million. As of March 31, 2009, we have accrued $0.5 million representing the most likely remaining cost of the remediation effort.

Dover, New Hampshire, Manufactured Gas Facility: In 1999, Public Service Company of New Hampshire ("PSNH") contacted us about this site. PSNH alleged that we were partially liable for cleanup, since the site was previously operated by Twin State Gas and Electric, which merged into CVPS on the same day that PSNH bought the facility. In 2002, we reached a settlement with PSNH in which certain liabilities we might have had were assigned to PSNH in return for a cash settlement paid by CVPS based on completion of PSNH's cleanup effort. Our remaining obligation was less than $0.1 million at March 31, 2009.

Reserve for Loss on Power Contract On January 1, 2004, we terminated a long-term power contract with Connecticut Valley Electric Company, a regulated electric utility that used to be our wholly owned subsidiary. In accordance with the requirements of SFAS 5, *Accounting for Contingencies*, we recorded a $14.4 million pre-tax loss accrual in the first quarter of 2004 related to the contract termination. The loss accrual represented our best estimate of the difference between expected future sales revenue in the wholesale market for the purchased power that was formerly sold to Connecticut Valley Electric Company and the net cost of purchased power obligations. We review this estimate at the end of each reporting period and will increase the reserve if the revised estimate exceeds the recorded loss accrual. The loss accrual is being amortized on a straight-line basis through 2015, the estimated life of the power contracts that were in place to supply power under the contract. The reserve was $8.1 million at March 31, 2009 and $8.4 million at December 31, 2008. The current and long-term portions are included as liabilities on the Condensed Consolidated Balance Sheets.

Catamount Indemnifications Under the terms of the agreements with Catamount and Diamond Castle, we agreed to indemnify them, and certain of their respective affiliates, in respect of a breach of certain representations and warranties and covenants, most of which ended June 30, 2007, except certain items that customarily survive indefinitely. Indemnification is subject to a $1.5 million deductible and a $15 million cap, excluding certain customary items. Environmental representations are subject to the deductible and the cap, and such environmental representations for only two of Catamount's underlying energy projects survived beyond June 30, 2007. Our estimated "maximum potential" amount of future payments related to these indemnifications is limited to $15 million. We have not recorded any liability related to these indemnifications.

NOTE 9 - SEGMENT REPORTING

The following table provides segment financial data for the three months ended March 31 (dollars in thousands). Inter-segment revenues were a nominal amount in all periods presented.

	CV-VT	Unregulated Companies	Reclassification & Consolidating Entries	Consolidated
March 31, 2009				
Revenues from external customers	**$ 90,727**	**$ 419**	**$ (419)**	**$ 90,727**
Net income	**$ 6,817**	**$ 55**	**$ 0**	**$ 6,872**
Total assets at March 31, 2009	**$ 625,720**	**$ 2,000**	**$ (224)**	**$ 627,496**
March 31, 2008				
Revenues from external customers	$ 91,224	$ 432	$ (432)	$ 91,224
Net income	$ 5,830	$ 78	$ 0	$ 5,908
Total assets at December 31, 2008	$ 624,341	$ 3,184	$ (1,399)	$ 626,126

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

In this section we discuss our general financial condition and results of operations. Certain factors that may impact future operations are also discussed. Our discussion and analysis is based on, and should be read in conjunction with, the accompanying Condensed Consolidated Financial Statements. The discussion below also includes non-GAAP measures referencing earnings per diluted share for variances described below in Results of Operations. We use this measure to provide additional information and believe that this measurement is useful to investors to evaluate the actual performance and contribution of our business activities. This non-GAAP measure should not be considered as an alternative to our consolidated fully diluted earnings per share determined in accordance with GAAP as an indicator of our operating performance.

Forward-looking statements Statements contained in this report that are not historical fact are forward-looking statements within the meaning of the 'safe-harbor' provisions of the Private Securities Litigation Reform Act of 1995. Whenever used in this report, the words "estimate," "expect," "believe," or similar expressions are intended to identify such forward-looking statements. Forward-looking statements involve estimates, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Actual results will depend upon, among other things:

- the actions of regulatory bodies with respect to allowed rates of return, continued recovery of regulatory assets and application of alternative regulation;
- liquidity risks;
- performance and continued operation of the Vermont Yankee nuclear power plant;
- changes in the cost or availability of capital;
- our ability to replace or renegotiate our long-term power supply contracts;
- effects of and changes in local, national and worldwide economic conditions;
- effects of and changes in weather;
- volatility in wholesale power markets;
- our ability to maintain or improve our current credit ratings;
- the operations of ISO-New England;
- changes in financial or regulatory accounting principles or policies imposed by governing bodies;
- capital market conditions, including price risk due to marketable securities held as investments in trust for nuclear decommissioning, pension and postretirement medical plans;
- changes in the levels and timing of capital expenditures, including our discretionary future investments in Transco;
- our ability to replace a mature workforce and retain qualified, skilled and experienced personnel; and
- other presently unknown or unforeseen factors.

We cannot predict the outcome of any of these matters; accordingly, there can be no assurance as to actual results. We undertake no obligation to publicly update any forward-looking statements, whether as a result of new information, future events or otherwise.

EXECUTIVE SUMMARY

Our core business is the Vermont electric utility business. The rates we charge for retail electricity sales are regulated by the Vermont Public Service Board ("PSB"). Fair regulatory treatment is fundamental to maintaining our 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. As discussed under the heading Retail Rates and Alternative Regulation below, the PSB approved the plan that we proposed in August 2007, with modifications. The implementation of this plan will provide more timely adjustments to power, operating and maintenance costs, which will better serve the interests of customers and shareholders.

Our consolidated earnings for the first quarter of 2009 were $6.9 million or 58 cents per diluted share of common stock, and $5.9 million, or 56 cents per diluted share of common stock for the same period in 2008. The primary drivers of the first quarter year-over-year earnings variance are described in Results of Operations below.

We continue to focus on key strategic financial initiatives including: restoring our corporate credit rating to investment-grade; ensuring that our retail rates are set at levels to recover our costs of service; evaluating financing options to support current and future working capital needs; planning for replacement power when long-term power contracts begin to expire in 2012; and implementing our asset management plan to ensure we continue to provide safe, reliable service to our customers at the lowest possible cost.

RETAIL RATES AND ALTERNATIVE REGULATION

Retail Rates Our retail rates are approved by the PSB after considering the recommendations of Vermont's consumer advocate, the Vermont Department of Public Service ("DPS"). Fair regulatory treatment is fundamental to maintaining our 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 return on common equity of our regulated business did not exceed the allowed return for 2008.

On September 30, 2008, the PSB issued an order approving, with modifications, the alternative regulation plan proposal that we submitted in August 2007. The plan became effective on November 1, 2008. It expires on December 31, 2011, but we have an option to petition for an extension beyond 2011. The plan replaces the traditional ratemaking process and allows for quarterly rate adjustments to reflect changes in power supply and transmission-by-others costs ("PCAM adjustment"); annual base rate adjustments to reflect changing costs; and annual rate adjustments to reflect changes, within predetermined limits, from the allowed earnings level. Under the plan, the allowed return on equity will be adjusted annually to reflect one-half of the change in the yield on the 10-year Treasury note as measured over the last 20 trading days prior to October 15 of each year. The earnings sharing adjustment mechanism ("ESAM") within the plan provides for the return on equity of the regulated portion of our business to fall between 75 basis points above or below the allowed return on equity before any adjustment is made. If the actual return on equity of the regulated portion of our business exceeds 75 basis points above the allowed return, the excess amount is returned to ratepayers in a future period. If the actual return on equity of our regulated business falls between 75 and 100 basis points below the allowed return on equity, the shortfall is shared equally between shareholders and ratepayers. Any earnings shortfall in excess of 100 basis points below the allowed return on equity is recovered from ratepayers. These adjustments are made at the end of each fiscal year.

The PCAM adjustment and the ESAM are not subject to PSB suspension, but the PSB may open an investigation and to the extent it finds, after notice and hearing, that the calculation was inaccurate or reflects costs inappropriate for inclusion in rates, it may require a modification of the of the associated adjustments to the extent necessary to correct the deficiencies.

On October 31, 2008, we submitted a base rate filing for the rate year commencing January 1, 2009 that reflected a 0.33 percent increase in retail rates. The result of the return on equity adjustment for 2009, in accordance with the plan, was a reduction of 0.44 percent, resulting in an allowed return on equity for 2009 of 9.77 percent. On November 17, 2008, the DPS filed a request for suspension and investigation of our filing. Citing concerns about staffing levels and inadequate supporting documentation for some proposed plant additions, the DPS recommended a 0.43 percent rate decrease.

On December 17, 2008, we filed a Memorandum of Understanding with the PSB setting forth agreements that we reached with the DPS regarding the PSB's investigation into our 2009 retail rates. Pursuant to the Memorandum of Understanding, we agreed to leave rates unchanged, with no increase or decrease, and that we and the DPS would request the PSB to open a docket to resolve the DPS's concerns regarding our level of staffing. On February 13, 2009, the PSB approved the Memorandum of Understanding, and ordered the rate investigation closed.

On February 2, 2009, we filed a motion with the PSB requesting to defer the incremental 2008 storm costs through our alternative regulation plan and collect through the ESAM over 12 months beginning on July 1, 2009. On February 3, 2009, the DPS filed a letter supporting our motion and on February 12, 2009, the PSB approved the request. The amount of the deferral, based on actual costs, was $3.2 million.

The first quarter 2009 PCAM adjustment was calculated to be an over collection of $0.6 million and was recorded as a regulatory liability. The over collection will be returned to customers over three months beginning July 1, 2009.

On February 13, 2009, the PSB opened an investigation into the staffing levels of the company as requested by us and the DPS. On March 25, 2009, the PSB convened a prehearing conference where we and the DPS agreed to a procedural schedule, and technical hearings are scheduled for June 2009. We and the DPS further agreed that the scope of the technical hearings could be narrowed to devising a methodology for deriving productivity measures that would be tracked over time. The parties do not agree, however, as to what the substantive elements of that tracking methodology should be. Accordingly, the PSB ordered that the purpose of hearings in this proceeding will be to resolve this disagreement about the makeup of the productivity tracking methodology.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows At March 31, 2009, we had cash and cash equivalents of $13.5 million compared to $6.4 million at March 31, 2008. The primary components of cash flows from operating, investing and financing activities for both periods are discussed in more detail below.

Operating Activities: Operating activities provided $15.1 million in the first quarter of 2009. Net income, when adjusted for depreciation, amortization, deferred income tax and other non-cash income and expense items, provided $12.3 million. This included $2.5 million of distributions received from affiliates, most materially from our investments in Transco. In addition, changes in working capital and other items provided $2.8 million, including a $6.5 million income tax refund.

During the first quarter of 2008, operating activities provided $11.2 million. Net income, when adjusted for depreciation, amortization, deferred income tax and other non-cash income and expense items, provided $9.7 million. This included $1.3 million of distributions received from affiliates, most materially from our investments in Transco. In addition, changes in working capital and other items provided $1.5 million.

Investing Activities: Investing activities used $5.9 million in the first quarter of 2009, including $5.8 million of construction and plant expenditures, and $0.1 million for other investing activities. During 2008, investing activities used $7.3 million in the first quarter of 2008 for construction and plant expenditures.

Financing Activities: In the first quarter of 2009, financing activities used $2.4 million, including $2.8 million for dividends paid on common and preferred stock, $1 million for preferred stock sinking fund payments, and $0.3 million for capital lease payments and other financing activities. These items were partially offset by $0.7 million from exercised stock options and the dividend reinvestment program and a $1 million reduction in special deposits for preferred stock sinking fund payments.

During the first quarter of 2008, financing activities used $1.3 million, including $2.4 million for dividends paid on common and preferred stock, $1 million for preferred stock sinking fund payments, and $0.2 million for capital lease payments. These items were partially offset by $1.2 million from exercised stock options and the dividend reinvestment program, a $1 million reduction in special deposits for preferred stock sinking fund payments, and $0.1 million for other financing activities.

Financing *Credit Facility:* We have a three-year, $40 million unsecured revolving credit facility with a lending institution pursuant to a credit agreement dated November 3, 2008. Our obligation under the credit agreement is guaranteed by our wholly owned, unregulated subsidiaries, C.V. Realty and CRC. The purpose of the facility is to provide liquidity for general corporate purposes, including working capital needs and power contract performance assurance requirements, in the form of funds borrowed and letters of credit. At March 31, 2009, there was less than $0.1 million in borrowings and no letters of credit outstanding under the credit facility.

Refinancing Plans: We are currently reviewing options to support working capital needs resulting from investments in our distribution and transmission system.

Covenants: At March 31, 2009, we were in compliance with all financial covenants related to our various debt agreements, articles of association, letters of credit and credit facility. A significant reduction in future earnings or a significant reduction to common equity could restrict the payment of common and preferred dividends or could cause us to violate our maintenance covenants. If we were to default on our covenants, the lenders could take such actions as terminate their obligations, declare all amounts outstanding or due immediately payable, or take possession of or foreclose on mortgaged property.

Investment opportunities in Transco Based on current projections, Transco expects to receive additional capital in 2009, 2010 and 2011, but its projections are subject to change based on a number of factors, including revised construction estimates, timing of project approvals from regulators, and desired changes in its equity-to-debt ratio. While we have no obligation to make additional investments in Transco, we continue to evaluate investment opportunities on a case-by-case basis. Based on Transco's current projections, we could have an opportunity to make additional investments of up to $21 million in 2009, $24 million in 2010 and $16 million in 2011, but the timing and amount depend on the factors discussed above and the amounts invested by other owners.

We are currently evaluating options to fund these investments, but any investments that we make in Transco are voluntary, and subject to available capital and appropriate regulatory approvals.

Capital spending We expect to invest approximately $30 million to $35 million in 2009 primarily in our transmission and distribution infrastructure to ensure continued system reliability. This compares to capital expenditures of $36.8 million in 2008. These estimates are subject to continuing review and adjustment, and actual capital expenditures and timing may vary. As of March 31, 2009 capital expenditures were $5.8 million.

Performance Assurance We are subject to performance assurance requirements through ISO-New England under the Financial Assurance Policy of the FERC-approved tariff for NEPOOL members. We are required to post collateral for all net purchased power transactions since our credit limit with ISO-New England is zero. Additionally, we are currently selling power in the wholesale market pursuant to contracts with third parties, and are required to post collateral under certain conditions defined in the contracts.

At March 31, 2009, we had posted $8.1 million of collateral under performance assurance requirements for ISO-New England and certain third party power contracts, of which $2.5 million was in cash and $5.6 million was represented by restricted cash. At December 31, 2008, we had posted $6.9 million of collateral under performance assurance requirements for certain power contracts, of which $3.3 million was in cash and $3.6 million was represented by restricted cash.

We are also subject to performance assurance requirements under our Vermont Yankee power purchase contract (the 2001 Amendatory Agreement). If Entergy-Vermont Yankee, the seller, has commercially reasonable grounds to question our ability to pay for our monthly power purchases, Entergy-Vermont Yankee may ask VYNPC and VYNPC may then ask us to provide adequate financial assurance of payment. We have not had to post collateral under this contract.

Cash flow risks Based on our current cash forecasts, we will require outside capital in addition to cash flow from operations and our $40 million unsecured revolving credit facility in order to fund our business over the next few years. Continued upheaval in the capital markets could negatively impact our ability to obtain outside capital on reasonable terms. If we were ever unable to obtain needed capital, we would re-evaluate and prioritize our planned capital expenditures and operating activities. In addition, an extended unplanned Vermont Yankee plant outage or similar event could significantly impact our liquidity due to the potentially high cost of replacement power and performance assurance requirements arising from purchases through ISO-New England or third parties. In the event of an extended Vermont Yankee plant outage, we could seek emergency rate relief from our regulators in addition to applying the proceeds of the Vermont Yankee forced outage insurance policy. Other material risks to cash flow from operations include: loss of retail sales revenue from unusual weather; slower-than-anticipated load growth and unfavorable economic conditions; increases in net power costs largely due to lower-than-anticipated margins on sales revenue from excess power or an unexpected power source interruption; required prepayments for power purchases; and increases in performance assurance requirements. See Retail Rates and Alternative Regulation above for additional information related to mechanisms designed to mitigate utility-related risks.

Off-balance-sheet arrangements We do not use off-balance-sheet financing arrangements, such as securitization of receivables, nor obtain access to assets through special purpose entities.

Prior to October 24, 2008, we leased our vehicles and related equipment under a single operating lease agreement. The individual leases under this agreement were mutually cancelable one year from lease inception. On November 14, 2008, we received notification from the lessor that this operating lease agreement was being terminated. Under the terms of the lease, we will be required to terminate all agreements under this lease by November 14, 2009 and pay the unamortized value of the equipment upon termination either by purchasing the equipment or through the sale of the equipment to a third party. At March 31, 2009, the unamortized value upon termination is $7.7 million.

On October 24, 2008, we entered into a second operating lease for vehicles and other related equipment with a different lessor. The lease schedules under this agreement are non-cancellable. At the end of the lease term, the lessor is entitled to recover a termination rental adjustment equal to 20 percent of the acquisition cost of the equipment. This payment can be recovered from us or through disposition of the equipment. In the case of disposition for less than 20 percent of the acquisition cost, our guarantee obligation is limited to 5 percent of the acquisition cost. If the entire lease portfolio had a fair value of zero at March 31, 2009, we would have been responsible for a maximum reimbursement of $2.2 million.

Global Economic Crisis Due to the global economic crisis, there has been a significant decline in lending activity. We expect to have access to liquidity in the capital markets when needed at reasonable rates. We also have access to a $40 million unsecured revolving credit facility. However, sustained turbulence in the global credit markets could limit or delay our access to capital. As part of our enterprise risk management, we are constantly monitoring our risks by reviewing our investments in various firms and financial institutions.

ACCOUNTING MATTERS

Critical accounting policies and estimates Our financial statements are prepared in accordance with U.S. GAAP, requiring us to make estimates and judgments that affect reported amounts of assets and liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities at the date of the Condensed Consolidated Financial Statements. Our critical accounting policies and estimates are described in Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2008 Annual Report on Form 10-K.

Recent Accounting Pronouncements *FASB Codification*: In March 2009, the FASB issued an exposure draft, *The Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB No. 162.* The proposed standard, FASB Accounting Standards Codification™ ("Codification") does not change U. S. GAAP, but combines all authoritative standards such as those issued by the FASB, AICPA, and EITF, into a comprehensive, topically organized online database. The Codification is expected to become the single source of authoritative U. S. GAAP applicable for all nongovernmental entities, except for rules and interpretive releases of the SEC. The final standard is expected to be effective on July 1, 2009.

See Note 1 - Business Organization and Summary of Significant Accounting Policies for a discussion of newly adopted accounting policies and recently issued accounting pronouncements.

RESULTS OF OPERATIONS

The following is a detailed discussion of the results of operations for the first quarter of 2009 compared to the same period in 2008. It should be read in conjunction with the Condensed Consolidated Financial Statements and accompanying notes included in this report.

Overview Our first quarter 2009 earnings increased by $1 million, or 2 cents per diluted share of common stock, compared to the same period in 2008. The table below provides a reconciliation of the primary year-over-year variances in diluted earnings per share. The earnings per diluted share for each variance shown below are non-GAAP measures:

2008 Earnings per diluted share	$ 0.56
Lower purchased power expense	0.07
Lower other operating expenses	0.04
Higher equity in earnings of affiliates	0.02
Common stock issuance (Nov. 2008) - 1,190,000 additional shares	(0.07)
Lower operating revenues	(0.03)
Higher transmission expense	(0.02)
Higher interest expense	(0.01)
Other	0.02
2009 Earnings per diluted share	**$ 0.58**

Note: The additional shares from the Nov. 2008 stock issuance were excluded from the 11,655,175 average shares of common stock - diluted for purposes of computing the individual EPS variances shown above in order to provide comparable information for 2009 vs. 2008.

Operating Revenues Operating revenues and related mWh sales for the three months ended March 31 are summarized below.

	Revenue		mWh Sales	
	2009	2008	**2009**	2008
Residential	**$ 38,966**	$ 38,512	**284,094**	280,995
Commercial	**25,837**	26,799	**209,033**	219,751
Industrial	**8,810**	9,630	**96,280**	104,925
Other	**470**	465	**1,586**	1,570
Total retail sales	**74,083**	75,406	**590,993**	607,241
Resale sales	**13,933**	13,502	**203,848**	205,137
Provision for rate refund	**0**	(62)	**0**	0
Other operating revenues	**2,711**	2,378	**0**	0
Total operating revenues	**$ 90,727**	$ 91,224	**794,841**	**812,378**

Operating revenues decreased $0.5 million in the first quarter of 2009 as compared to 2008 due to the following:

- Retail sales decreased $1.3 million comprised of a $1.7 million decrease due to lower sales volume, partly offset by a $0.4 million increase due to higher average retail rates. Sales volume decreased due to lower average usage by commercial and industrial customers resulting from economic conditions.
- Resale sales increased $0.4 million resulting from higher average prices from new contracts.
- The provision for rate refund was a reduction in operating revenues related to amounts that were included in retail rates in 2007 and January 2008 that were to be refunded to customers. It ended with retail rates effective February 1, 2008 because the customer refund was included in the new rates.
- Other operating revenues increased $0.3 million from sales of additional transmission capacity from our share of Phase I/II transmission facility rights and an increase in wholesale rates. We began selling transmission capacity in April 2007, and we have the ability to restrict the amount of capacity assigned to the purchasers based on certain conditions. Revenue from these sales is estimated to be approximately $1.8 million annually in 2009 and 2010.

Operating Expenses Operating expenses decreased $0.7 million in the first quarter of 2009 as compared to 2008. Significant variances in operating expenses on the Condensed Consolidated Statements of Income are described below.

Purchased Power: Purchased power expense and volume for the three months ended March 31 are summarized below.

	Purchases (in thousands)		mWh Purchases	
	2009	2008	**2009**	2008
VYNPC	**$ 15,733**	$ 15,900	**386,711**	393,572
Hydro-Quebec	**17,059**	16,421	**268,162**	251,089
Independent Power Producers ("IPPs")	**5,909**	7,904	**47,952**	56,306
Subtotal long-term contracts	**38,701**	40,225	**702,825**	700,967
Other purchases	**2,380**	1,744	**13,403**	16,526
SFAS No. 5 loss amortizations	**(299)**	(299)	**-**	-
Maine Yankee, Connecticut Yankee and Yankee Atomic	**329**	568	**-**	-
Amortizations and deferrals	**499**	668	**-**	-
Total purchased power	**41,610**	42,906	716,228	717,493

Purchased power decreased $1.3 million in the first quarter of 2009 compared to the same period in 2008 as a result of the following:

- Purchases under long-term contracts decreased $1.5 million largely due to the Nov. 2008 termination of one IPP participant, resulting in fewer required IPP purchases at lower prices and lower output from VYNPC. This decrease was partially offset by increased deliveries from Hydro-Quebec, higher energy prices under the Hydro-Quebec and VYNPC contracts and a lower nuclear insurance refund from VYNPC. The impact of the nuclear insurance is offset in amortizations and deferrals discussed below.
- Other purchases increased $0.6 million resulting from higher average prices.
- Nuclear decommissioning costs decreased $0.2 million. These costs are associated with our ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. Their costs are based on FERC-approved tariffs.
- Amortizations and deferrals decreased $0.2 million. These amortizations and deferrals are based on PSB-approved regulatory accounting, and include net accounting deferrals and amortizations for incremental energy costs related to Millstone Unit #3 scheduled refueling outages and deferrals for our share of nuclear insurance refunds received by VYNPC.

Transmission - affiliates: These expenses represent our share of the net cost of service of Transco and some direct charges for facilities that we rent. Transco allocates its monthly cost of service through the Vermont Transmission Agreement ("VTA"), net of NEPOOL Open Access Transmission Tariff ("NOATT") reimbursements and certain direct charges. The NOATT is the mechanism through which the costs of New England's high-voltage transmission facilities are collected from load-serving entities using the system and redistributed to the owners of the facilities, including Transco. These expenses decreased $0.9 million due to higher NOATT reimbursements, partially offset by higher charges under the VTA resulting from Transco's capital projects.

Transmission - other: The majority of these expenses are for purchases of regional transmission service under the NOATT and charges for the Phase I and II transmission facilities. The increase of $1.2 million for the first quarter of 2009 versus 2008 primarily resulted from higher rates and overall transmission expansion in New England.

Maintenance: These expenses are associated with maintaining our electric distribution system and include costs of our jointly owned generating and transmission facilities. Maintenance expenses decreased $1.7 million in the first quarter of 2009, principally due to lower service restoration costs since we had major storms in 2008, and a decrease in tree trimming.

Income tax expense (benefit): Federal and state income taxes fluctuate with the level of pre-tax earnings in relation to permanent differences, tax credits, tax settlements and changes in valuation allowances for the periods discussed herein.

Other Income Significant variances in income statement line items that comprise other income on the Condensed Consolidated Statements of Income are described below.

Other deductions: These items include supplemental retirement benefits and insurance, including changes in the cash surrender value of life insurance policies, non-utility expenses relating to rental water heaters, and miscellaneous other deductions. Other deductions decreased $0.5 million, resulting from market gains on the cash surrender value of life insurance policies included in our Rabbi Trust.

Income tax expense: Federal and state income taxes fluctuate with the level of pre-tax earnings in relation to permanent differences, tax credits, tax settlements and changes in valuation allowances for the periods discussed herein.

Interest Expense Significant variances in income statement line items that comprise interest expense on the Condensed Consolidated Statements of Income are described below.

Interest on long-term debt: These expenses increased $0.9 million largely due to the $60 million first mortgage bonds issued in May 2008.

Other interest: These expenses decreased $0.7 million in the first quarter of 2009. The first quarter decrease resulted from a bridge loan that was repaid in May 2008 from proceeds of a long-term debt issue.

POWER SUPPLY MATTERS

Power Supply Management Our power supply portfolio includes a mix of baseload and dispatchable resources. These sources are used to serve our retail electric load requirements plus any wholesale obligations into which we enter. We manage our power supply portfolio by attempting to optimize the use of these resources, and through wholesale sales and purchases to create a balance between our power supplies and load obligations.

Our current power forecast shows energy purchase and production amounts in excess of load obligations through 2011. Due to the forecasted excess, we enter into fixed-price forward sale transactions to reduce price (revenue) volatility in order to help stabilize our net power costs. Our main supply risk is with the Vermont Yankee plant. We have a forced outage insurance policy to cover additional costs, if any, of obtaining replacement power from other sources if the Vermont Yankee plant experiences unplanned outages. The current policy is effective March 22, 2009 through March 21, 2010. This outage insurance does not apply to reductions in production levels at the plant (referred to as a "derate") or acts of terrorism. The coverage applies to unplanned outages of up to 90 consecutive calendar days per outage event, and provides for payment of the difference between the spot market price and $42/mWh. The aggregate maximum coverage is $9 million with a $1.2 million deductible.

We have entered into several forward sale contracts to sell a majority of our forecasted excess power in 2009. These transactions are for physical delivery except for one price swap transaction that settles financially. The swap effectively produces the same fixed-price result as a physical sale while reducing potential collateral requirements to ISO-New England. As discussed above, these transactions help to stabilize future resale revenue by reducing price volatility. We continue to work with counterparties in New England to sell forward our forecasted excess beyond 2009. Our current credit rating limits the number of counterparties we currently deal with, requires that we limit the net sale position with counterparties, and that we structure transactions to limit collateral exposures.

The operations of the Vermont Yankee plant can significantly impact our net power costs, which are comprised of costs for purchased power and our owned and jointly owned generating facilities, less resale revenue. Currently, the price that we pay for Vermont Yankee output under the long-term contract is lower than the market price. Therefore, increased plant output has a favorable effect on net power costs by displacing higher-priced short-term purchases and increasing opportunities for resale sales. Decreased plant output has an unfavorable effect on net power costs by increasing higher-priced short-term purchases and decreasing opportunities for resale sales.

In July 2008, the Vermont Yankee plant experienced a 12-day derate, reaching a low of approximately 17 percent capacity during some of that time. The derate resulted from issues related to the plant's cooling towers. The incremental cost of the replacement power that we purchased during that time was approximately $1.1 million. We also lost approximately $1.1 million in resale sales revenue during that time. We were able to apply approximately $0.1 million as a reduction in purchased power expense from a regulatory liability established for the difference in the premium we paid for Vermont Yankee forced outage insurance and amounts currently collected in retail rates.

In the third quarter of 2007, the Vermont Yankee plant experienced a derate, after the collapse of a cooling tower at the plant, and a two-day unplanned outage associated with a valve failure. We purchased replacement energy adequate to meet most of our hourly load obligations during that period. The derate and unplanned outage increased our net power costs by about $1.3 million in the third quarter of 2007 through increased purchased power expense and decreased operating revenues due to reduced resale sales. We were also able to apply $0.3 million as reduction in purchased power expense from the regulatory liability.

We are considering whether to seek recovery of the incremental costs from Entergy-Vermont Yankee under the terms of the PPA based upon the results of certain reports, including a recent NRC inspection, in which the inspection team found that Entergy-Vermont Yankee, among other things, did not have sufficient design documentation available to help it prevent problems with the cooling towers. The NRC released its findings on October 14, 2008. In considering whether or not to seek recovery, we are also reviewing the 2007 and 2008 root cause analysis reports by Entergy as well as the December 22, 2008 reliability assessment provided by the Nuclear Safety Associates to the State of Vermont. We cannot predict the outcome of this matter at this time.

Future Power Supply Our contract for power purchases from VYNPC ends in March 2012, but there is a risk that the plant could be shut down earlier than expected if Entergy-Vermont Yankee determines that it is not economical to continue operating the plant. Hydro-Quebec contract deliveries end in 2016, but the average level of deliveries decreases by approximately 20 percent to 30 percent after 2012, and by approximately 85 percent after 2015. These two contracts provide about two-thirds of our current power supply. There is a risk that future sources available to replace these contracts may not be as reliable and the price of such replacement power could be significantly higher than what we have in place today. These contracts are described in Note 8 - Commitments and Contingencies.

Entergy-Vermont Yankee has submitted a renewal application with the NRC for a 20-year extension of the Vermont Yankee plant operating license. Entergy-Vermont Yankee also needs approval from the PSB and Vermont Legislature to continue to operate beyond 2012. At this time, Entergy-Vermont Yankee has not received approvals for the license extension, but we are continuing to participate in negotiations for a power contract beyond 2012 and cannot predict the outcome at this time.

An early shutdown of the Vermont Yankee plant would cause us to lose the economic benefit of an energy volume of close to 50 percent of our total committed supply and we would have to acquire replacement power resources for approximately 40 percent of our estimated power supply needs. Based on projected market prices as of March 31, 2009, the incremental replacement cost of lost power, including capacity, is estimated to average $27.3 million annually. We are not able to predict whether there will be an early shutdown of the Vermont Yankee. An early shutdown could materially impact our financial position and future results of operations if the costs are not recovered in retail rates in a timely fashion. The PCAM adjustment within our alternative regulation plan will allow more timely recovery of power costs for 2009, 2010 and 2011

Power Supply Request For Proposal ("RFP") In November 2008, together with Green Mountain Power ("GMP") and Vermont Electric Cooperative ("VEC"), we issued a request for power supply proposals ("RFP") to diversify our future power supplies and plan for the expiration of major contracts with Vermont Yankee and Hydro-Quebec between March 2012 and 2016. We also issued a second solicitation, together with GMP, at the same time. The two RFPs are the first in a series of staggered resource solicitations planned to be issued over the next several years as we build our power supply portfolio for the future.

The RFPs were distributed to all NEPOOL participants, power suppliers and developers. Bidders from across the Northeast and Canada included powers marketers, energy developers, existing and to-be-built power plant owners and financial institutions. Because the three Vermont utilities are engaged in ongoing negotiations with Hydro-Quebec and Entergy-Vermont Yankee, neither entity was eligible to bid in the RFPs.

In the first RFP ("the Joint RFP"), the three Vermont utilities sought up to 100 MW of energy, comprised of up to 40 MW for each of us and GMP, and 20 MW for VEC. In total, bidders offered more than 1,800 MW providing a diversity of options. The second RFP ("the Contingent RFP"), issued by us and GMP, was for up to 150 MW of new energy and is contingent on the outcome of Vermont Yankee relicensing and contract negotiations.

Joint RFP responses were received in early January 2009 and final proposals were received on February 27, 2009. We determined that six of the proposals provide the best value under the portfolio scoring approach we submitted to the PSB as part of our Integrated Resource Planning proceedings. That evaluation methodology includes, as a threshold, an evaluation of credit or collateral terms. All bidders have been notified of our determinations, and negotiations with the successful bidders are under way. To date, we have executed one transaction for 15 MW of firm power to be delivered during 2013-2015. Two of the finalists are existing renewable power plants while another is in the final stages of permitting. We intend to negotiate long-term purchase power agreements with these parties.

Best and final proposals were due from bidders in the Contingent RFP on May 1, 2009. We expect to continue working with these parties at least until the uncertainties related to the Vermont Yankee plant's relicensing and the PPA negotiations are resolved. This process could remain unresolved until mid-2010.

At this time, we are unable to predict the impact on our financial statements and cash flows resulting from these awards and signed contracts associated with these RFPs.

RECENT ENERGY POLICY INITIATIVES

Alternative Regulation Plan In 2003, the Vermont legislature authorized alternative regulation plans. On September 30, 2008, the PSB issued an Order approving, with modifications, an alternative regulation plan proposal that we submitted in August 2007. Our plan became effective on November 1, 2008. It expires on December 31, 2011, but we have an option for an extension beyond 2011. The plan replaces the traditional ratemaking process and allows for annual base rate adjustments, quarterly rate adjustments to reflect power supply and transmission-by-others cost changes, and annual rate adjustments to reflect changes, within predetermined limits, from the allowed earnings level. See Retail Rates and Alternative Regulation.

Climate Change Legislation The Vermont legislature enacted legislation requiring the state to participate in the Regional Greenhouse Gas Initiative ("RGGI") . RGGI is a mandatory, market-based program with a goal of reducing greenhouse gas emissions. The program is designed to cap and then reduce CO_2 emissions from the power sector by 10 percent by 2018 for 10 northeastern and Mid-Atlantic states. To reach this goal, states sell emission allowances through auctions and invest the proceeds in programs, such as energy efficiency, renewable energy, and other clean energy technologies, for the benefit of consumers. The purpose of RGGI is to spur innovation in the clean energy economy and create "green jobs" in each state.

The PSB issued an order in July 2008 to implement the auction provisions of the RGGI program. The state expects to raise more than $2 million in each of the next several years, and expects to invest it in energy efficiency, renewable energy technologies and other programs.

In addition, over the past several years, the U. S. Congress has considered bills that would regulate domestic greenhouse gas emissions. While such bills have not yet received sufficient congressional approval to become law, there is growing consensus that some form of federal legislation or regulation is likely to occur in the near future with respect to greenhouse gas emissions. It is unknown how RGGI might be modified or coordinated with future federal legislation.

We will continue to monitor state and federal legislative developments to evaluate whether, and the extent to which, any resulting statutes or rules may affect our business, including the ability of our out-of-state power suppliers to meet their obligations.

We cannot predict the effects of any such legislation at this time. We anticipate that compliance with greenhouse gas emission limitations for all suppliers may entail replacement of existing equipment, installation of additional pollution control equipment, purchase of allowances, curtailment of certain operations or other actions. Capital expenditures or operating costs resulting from greenhouse gas emission legislation or regulations could be material, and could significantly increase the wholesale cost of power.

American Recovery and Reinvestment Act of 2009 In February 2009, the American Recovery and Reinvestment Act of 2009 ("ARRA") was enacted into law. ARRA contains various provisions related to the electric industry intended to stimulate the economy, including incentives for increased capital investment by businesses and incentives to promote renewable energy. These provisions include, but are not limited to, improving energy efficiency and reliability, electricity delivery (including so-called smart grid technology), energy research and development, and demand response management. We are currently evaluating the provisions, their impact on our operations and the potential for applying for stimulus funds. We cannot predict the impact of the ARRA on our financial statements at this time.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For the three months ended March 31, 2009, there were no material changes from the disclosures in our Annual Report on Form 10-K for the year ended December 31, 2008 except as shown below.

Power-related derivatives Our derivative financial instruments include certain power contracts and financial transmission rights. Summary information related to the fair value of these derivatives is shown in the table below (dollars in thousands).

	Forward Sales Contracts	Forward Purchase Contracts	Hydro-Quebec Sellback #3	Total
Total fair value at December 31, 2008 - unrealized gain (loss), net	$ 12,753	$ 136	$ (4,069)	$ 8,820
Plus new contracts entered into during the period		(855)		(855)
Less amounts settled during the period	(4,812)	(34)		(4,846)
Change in fair value during the period	7,481	(15)	707	8,173
Total fair value at March 31, 2009 - unrealized gain (loss), net	$ 15,422	$ (768)	$ (3,362)	$ 11,292
Estimated fair value at March 31, 2009 for changes in projected market price:				
10 percent increase	$ 13,676	$ (838)	$ 6,451	$ 19,289
10 percent decrease	$ 17,168	$ 2,624	$ 761	$ 20,553

Based on a PSB-approved Accounting Order, we record the changes in fair value of power-related derivative financial instruments as deferred charges or deferred credits on the balance sheet, depending on whether the fair value is an unrealized loss or gain. Realized gains and losses for forward power sales are recorded as increases to or reductions of operating revenues, respectively. For forward purchase contracts and financial transmission rights, realized gains and losses are recorded as reductions of or additions to purchased power expense, respectively. Realized amounts are recorded in the period when the contracts are settled.

Equity Market Risk As of March 31, 2009, our pension trust held marketable equity securities in the amount of $40.5 million, our postretirement medical trust funds held marketable equity securities in the amount of $5.6 million, our Millstone Unit #3 decommissioning trust held marketable equity securities of $2.2 million and our Rabbi Trust held marketable equity securities of $1.9 million. These equity investments have been affected by the global decline in the equity market. Also see Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources, and Pension and Postretirement Medical Plan above for additional information.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures As of the quarter ended March 31, 2009, our management, with participation from the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15 (e) under the Securities Exchange Act of 1934). Based on that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting There was one significant change to our internal control over financial reporting that occurred during the quarter ended March 31, 2009. Effective January 1, 2009, we implemented several SAP enterprise resource planning ("ERP") modules, including general ledger, consolidation, accounts payable, supply chain, fixed assets (property accounting), treasury, payroll and human resources. The implementation of these ERP modules and the related workflow capabilities resulted in material changes to our internal controls over financial reporting (as defined in Rules 13(a)-15(f) or 15(d)-15(f) under the Exchange Act). As a result, we are in the process of modifying the design and documentation of internal control processes and procedures relating to the new system to replace and supplement existing internal controls over financial reporting, as appropriate. Specifically, we modified controls in the business processes impacted by the new system, such as user access security, system reporting, and authorization and reconciliation procedures. The system changes were undertaken to integrate systems and consolidate information, and were not undertaken in response to any actual or perceived deficiencies in our internal controls over financial reporting.

There were no other changes in our internal control over financial reporting during the quarter ended March 31, 2009 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1. **Legal Proceedings.**

The company is involved in legal and administrative proceedings in the normal course of business and does not believe that the ultimate outcome of these proceedings will have a material adverse effect on its financial position or results of operations.

Item 1A. **Risk Factors.**

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I "Item 1A. Risk Factors", in our Annual Report on Form 10-K for the year ended December 31, 2008, which could materially affect our business, financial condition or future results. The risks described in our 2008 Annual Report on Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

Item 6. **Exhibits.**

(a) List of Exhibits

A 10.17 Management Incentive Plan, Effective as of January 1, 2009 (incorporated by reference to Exhibit A 10.17 to the Company's Form 8-K filed with the SEC on April 7, 2009).

31.1 Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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.

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
(Registrant)

By /s/ Pamela J. Keefe
Pamela J. Keefe
Senior Vice President, Chief Financial Officer, and Treasurer

Dated May 8, 2009