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 September 30, 2010

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 October 31, 2010 there were outstanding 13,110,711 shares of Common Stock, $6 Par Value.

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
Form 10-Q for Period Ended September 30, 2010

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Item 1. Financial Statements

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

	Three Months Ended September 30 2010	2009	Nine Months Ended September 30 2010	2009
Operating Revenues	**$85,392**	$81,791	**$256,336**	$255,145
Operating Expenses				
Purchased Power - affiliates	**16,817**	16,435	**43,889**	48,531
Purchased Power	**24,292**	21,241	**76,149**	69,360
Production	**3,169**	2,613	**8,785**	8,599
Transmission - affiliates	**(5,055)**	116	**(2,001)**	5,586
Transmission - other	**7,027**	6,575	**20,272**	17,335
Other operation	**10,597**	13,741	**42,279**	43,363
Maintenance	**6,637**	6,718	**21,755**	16,759
Depreciation	**4,399**	4,326	**13,081**	12,518
Taxes other than income	**4,473**	3,905	**13,686**	11,951
Income tax (benefit) expense	**4,407**	905	**5,454**	4,541
Total Operating Expenses	**76,763**	76,575	**243,349**	238,543
Utility Operating Income	**8,629**	5,216	**12,987**	16,602
Other Income				
Equity in earnings of affiliates	**5,347**	4,320	**15,857**	13,196
Allowance for equity funds during construction	**42**	15	**52**	146
Other income	**706**	765	**2,139**	2,246
Other deductions	**(257)**	(6)	**(1,857)**	(884)
Income tax expense	**(1,631)**	(1,186)	**(4,934)**	(4,008)
Total Other Income	**4,207**	3,908	**11,257**	10,696
Interest Expense				
Interest on long-term debt	**2,750**	2,781	**8,292**	8,374
Other interest	**117**	154	**343**	451
Allowance for borrowed funds during construction	**(21)**	(11)	**(28)**	(96)
Total Interest Expense	**2,846**	2,924	**8,607**	8,729
Net Income	**9,990**	6,200	**15,637**	18,569
Dividends declared on preferred stock	**92**	92	**276**	276
Earnings available for common stock	**$9,898**	$6,108	**$15,361**	$18,293
Per Common Share Data:				
Basic earnings per share	**$0.79**	$0.52	**$1.27**	$1.57
Diluted earnings per share	**$0.79**	$0.52	**$1.27**	$1.57
Average shares of common stock outstanding - basic	**12,516,488**	11,679,133	**12,109,796**	11,647,626
Average shares of common stock outstanding - diluted	**12,545,987**	11,717,218	**12,140,191**	11,685,795
Dividends declared per share of common stock	**$0.23**	$0.23	**$0.92**	$0.92

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 September 30		Nine months ended September 30	
	2010	2009	**2010**	2009
Net Income	**$9,990**	$6,200	**$15,637**	$18,569
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, $1, $0 and $2	**0**	1	**0**	2
Prior service cost, net of income taxes of $0, $2, $0 and $7	**0**	3	**0**	10
Comprehensive income adjustments	**0**	4	**0**	12
Total comprehensive income	**$9,990**	$6,204	**$15,637**	$18,581

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)	Nine months ended September 30	
Cash flows provided (used) by:	**2010**	2009
OPERATING ACTIVITIES		
Net income	**$15,637**	$18,569
Adjustments to reconcile net income to net cash provided by operating activities:		
Equity in earnings of affiliates	**(15,857)**	(13,196)
Distributions received from affiliates	**10,788**	7,969
Depreciation	**13,081**	12,518
Deferred income taxes and investment tax credits	**15,641**	6,393
Regulatory and other amortization, net	**(2,446)**	(118)
Non-cash employee benefit plan costs	**4,884**	4,791
Other non-cash expense and (income), net	**(573)**	3,677
Changes in assets and liabilities:		
Decrease (increase) in accounts receivable and unbilled revenues	**188**	(1,758)
(Decrease) increase in accounts payable	**(2,346)**	1,138
Change in prepaid and accrued income taxes	**(884)**	3,974
(Increase) decrease in other current assets	**(1,726)**	1,234
Decrease (increase) in special deposits and restricted cash for power collateral	**5,370**	(1,683)
Employee benefit plan funding	**(6,351)**	(6,863)
Increase (decrease) in other current liabilities	**1,330**	(3,501)
Decrease in other long-term assets and liabilities and other	**1,306**	182
Net cash provided by operating activities	**38,042**	33,326
INVESTING ACTIVITIES		
Construction and plant expenditures	**(21,012)**	(21,263)
Investments in available-for-sale securities	**(1,146)**	(3,279)
Proceeds from sale of available-for-sale securities	**937**	3,022
Other investing activities	**(402)**	(450)
Net cash used for investing activities	**(21,623)**	(21,970)
FINANCING ACTIVITIES		
Net proceeds from the issuance of common stock	**18,489**	1,318
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	**(8,605)**	(8,308)
Proceeds from revolving credit facility	**114,043**	13,395
Repayments under revolving credit facility	**(137,354)**	(13,395)
Common stock offering and debt issuance costs	**(322)**	(67)
Other financing activities	**(794)**	(745)
Net cash used by financing activities	**(14,543)**	(7,802)
Net increase in cash and cash equivalents	**1,876**	3,554
Cash and cash equivalents at beginning of the period	**2,069**	6,722
Cash and cash equivalents at end of the period	**$3,945**	$10,276

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)

	September 30, 2010	December 31, 2009
ASSETS		
Utility plant		
Utility plant, at original cost	**$607,150**	$593,211
Less accumulated depreciation	**265,066**	254,858
Utility plant, at original cost, net of accumulated depreciation	**342,084**	338,353
Property under capital leases, net	**4,550**	5,302
Construction work-in-progress	**14,445**	10,235
Nuclear fuel, net	**1,757**	2,190
Total utility plant, net	**362,836**	356,080
Investments and other assets		
Investments in affiliates	**134,802**	129,733
Non-utility property, less accumulated depreciation ($3,639 in 2010 and $3,661 in 2009)	**1,900**	1,900
Millstone decommissioning trust fund	**5,319**	5,082
Other	**6,875**	6,542
Total investments and other assets	**148,896**	143,257
Current assets		
Cash and cash equivalents	**3,945**	2,069
Restricted cash	**0**	5,369
Special deposits	**6**	1,007
Accounts receivable, less allowance for uncollectible accounts ($3,143 in 2010 and $3,577 in 2009)	**26,430**	24,597
Accounts receivable - affiliates, less allowance for uncollectible accounts	**1,997**	40
Unbilled revenues	**16,359**	20,827
Materials and supplies, at average cost	**6,741**	6,219
Prepayments	**16,989**	14,055
Deferred income taxes	**3,288**	3,351
Power-related derivatives	**2,689**	622
Other current assets	**2,810**	2,252
Total current assets	**81,254**	80,408
Deferred charges and other assets		
Regulatory assets	**45,962**	46,240
Other deferred charges – regulatory	**4,499**	1,544
Other deferred charges and other assets	**2,850**	4,623
Total deferred charges and other assets	**53,311**	52,407
TOTAL ASSETS	**$646,297**	$632,152

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)

	September 30, 2010	December 31, 2009
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common stock, $6 par value, 19,000,000 shares authorized, 14,789,044 issued and 12,659,971 outstanding at September 30, 2010 and 13,835,968 issued and 11,706,895 outstanding at December 31, 2009	**$88,734**	$83,016
Other paid-in capital	**84,860**	72,179
Accumulated other comprehensive loss	**(209)**	(209)
Treasury stock, at cost, 2,129,073 shares at September 30, 2010 and December 31, 2009	**(48,436)**	(48,436)
Retained earnings	**129,017**	124,873
Total common stock equity	**253,966**	231,423
Preferred and preference stock not subject to mandatory redemption	**8,054**	8,054
Long-term debt	**158,300**	201,611
Capital lease obligations	**3,609**	4,313
Total capitalization	**423,929**	445,401
Current liabilities		
Current portion of preferred stock subject to mandatory redemption	**0**	1,000
Current portion of long-term debt	**20,000**	0
Accounts payable	**8,083**	9,016
Accounts payable – affiliates	**10,448**	12,040
Nuclear decommissioning costs	**1,607**	1,443
Power-related derivatives	**0**	219
Other current liabilities	**30,026**	26,450
Total current liabilities	**70,164**	50,168
Deferred credits and other liabilities		
Deferred income taxes	**77,206**	59,215
Deferred investment tax credits	**2,450**	2,642
Nuclear decommissioning costs	**5,859**	7,055
Asset retirement obligations	**3,390**	3,247
Accrued pension and benefit obligations	**35,112**	38,056
Power-related derivatives	**0**	149
Other deferred credits – regulatory	**6,786**	3,888
Other deferred credits and other liabilities	**21,401**	22,331
Total deferred credits and other liabilities	**152,204**	136,583
Commitments and contingencies		
TOTAL CAPITALIZATION AND LIABILITIES	**$646,297**	$632,152

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	Shares	Amount	Other Paid-in Capital	Accumulated Other Comprehensive Loss	Retained Earnings	Total
Balance, December 31, 2009	13,835,968	$83,016	(2,129,073)	($48,436)	$72,179	($209)	$124,873	$231,423
Net income							15,637	15,637
Other comprehensive income								0
Common Stock Issuance, net of issuance costs	848,057	5,088			11,657			16,745
Dividend reinvestment plan	52,314	314			728			1,042
Stock options exercised	35,100	210			301			511
Share-based compensation:								
Common & nonvested shares	2,484	15			40			55
Performance share plans	15,121	91			(59)			32
Dividends declared:								
Common - $0.92 per share							(11,215)	(11,215)
Cumulative non-redeemable preferred stock							(276)	(276)
Amortization of preferred stock issuance expense					12			12
Gain (Loss) on capital stock					2		(2)	0
Balance, September 30, 2010	14,789,044	$88,734	(2,129,073)	($48,436)	$84,860	($209)	$129,017	$253,966

	Common Stock		Treasury Stock					
	Shares Issued	Amount	Shares	Amount	Other Paid-in Capital	Accumulated Other Comprehensive Loss	Retained Earnings	Total
Balance, December 31, 2008	13,750,717	$82,504	(2,175,892)	($49,501)	$71,489	($228)	$115,215	$219,479
Net income							18,569	18,569
Other comprehensive income						12		12
Common Stock Issuance, net of issuance costs					(54)			(54)
Dividend reinvestment plan			48,621	1,076				1,076
Stock options exercised	36,160	217			284			501
Share-based compensation:								
Common & nonvested shares	2,400	14			29			43
Performance share plans	25,093	151			(34)			117
Dividends declared:								
Common - $0.92 per share							(10,719)	(10,719)
Cumulative non-redeemable preferred stock							(276)	(276)
Amortization of preferred stock issuance expense					12			12
Gain (Loss) on capital stock					(138)		(3)	(141)
Balance, September 30, 2009	13,814,370	$82,886	(2,127,271)	($48,425)	$71,588	($216)	$122,786	$228,619

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 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").

In the third quarter of 2010, our wholly owned subsidiary, Custom Investment Corporation, which held our investment in VYNPC, was dissolved and the VYNPC shares were transferred to the company. There was no impact on our financial statements or results of operations.

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. The accompanying unaudited condensed consolidated interim financial statements contain all normal, recurring adjustments considered necessary to present fairly the financial position as of September 30, 2010, the results of operations for the three-month and nine-month periods ended September 30, 2010 and 2009 and cash flows for the nine-month periods ended September 30, 2010 and 2009. The results of operations for the interim periods presented herein may not be indicative of the results that may be expected for the full year. These financial statements 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, 2009.

We consider subsequent events or transactions that occur after the balance sheet date, but before the financial statements are issued, to provide additional evidence relative to certain estimates or to identify matters that require additional disclosure.

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 required, we prepare our financial statements in accordance with the Financial Accounting Standards Board's ("FASB") guidance for regulated operations. The application of this guidance results in differences in the timing of recognition of certain expenses from those of other businesses and industries. For us to report our results under the accounting for regulated operations, 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 the majority of these costs becomes unlikely or uncertain, whether due to competition or regulatory action, we would reassess whether this accounting standard would continue to apply to our regulated operations. In the event we determine that we no longer meet the criteria for applying the accounting for regulated operations, the accounting impact would be a charge to operations of an amount that would be material unless stranded cost recovery is allowed through a rate mechanism. 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. Criteria that could give rise to the discontinuance of accounting for regulated operations include: 1) increasing competition that restricts a company's ability to establish prices to recover specific costs, and 2) a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. In the event that we no longer meet the criteria under the guidance for regulated operations and there is not a rate mechanism to recover these costs, the impact would, among other things, result in a charge to operations. See Note 7 - Retail Rates and Regulatory Accounting for additional information.

Derivative Financial Instruments We account for certain power contracts as derivatives under the provisions of FASB's guidance for derivatives and hedging. This guidance requires 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. Contracts that qualify for the normal purchase and sale exception are not included in derivative assets and liabilities. Additionally, we have not elected hedge accounting for our power-related derivatives.

Based on a PSB-approved Accounting Order, we record the changes in fair value of all power-related derivative financial instruments as deferred charges or deferred credits on the balance sheet, depending on whether the change in fair value is an unrealized loss or gain. The corresponding offsets 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 one forward energy contract, one long-term purchased power contract that allows the seller to repurchase specified amounts of power with advance notice ("Hydro-Québec 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 10 - Power-Related Derivatives.

Government Grants We recognize government grants when there is reasonable assurance that we will comply with the conditions attached to the grant arrangement and the grant will be received. Government grants are recognized in the Condensed Consolidated Statements of Income over the periods in which we recognize the related costs for which the government grant is intended to compensate. When government grants are related to reimbursements of operating expenses, the grants are recognized as a reduction of the related expense in the Condensed Consolidated Statements of Income. For government grants related to reimbursements of capital expenditures, the grants are recognized as a reduction of the basis of the asset and recognized in the Condensed Consolidated Statements of Income over the estimated useful life of the depreciable asset as reduced depreciation expense.

We record government grants receivable in the Condensed Consolidated Balance Sheets in Accounts Receivable. For additional information see Note 7 – Retail Rates and Regulatory Accounting – CVPS SmartPower^{TM}.

Our current rates include the recovery of costs that are eligible for government grant reimbursement by the United States Department of Energy ("DOE") under the American Recovery and Reinvestment Act; however, the grant reimbursement is not reflected in our current rates. Grant reimbursements are recorded to a regulatory liability until they are reflected in rates.

Supplemental Financial Statement Data Supplemental financial information for the accompanying financial statements is provided below.

Prepayments: The components of Prepayments on the Consolidated Balance Sheets at September 30 follow (dollars in thousands):

	September 30, 2010	December 31, 2009
Income Taxes	**$14,214**	$11,500
Miscellaneous	**2,775**	2,555
Total	**$16,989**	**$14,055**

For additional information, see Note 12 – Income Taxes.

Recently Adopted Accounting Policies
Variable Interest Entities: In June 2009, the FASB issued additional consolidation guidance related to variable interest entities and includes the addition of entities previously considered qualifying special-purpose entities.

We have an equity investment in and long-term power purchase agreement with VYNPC ("VY PPA"). VYNPC has a power purchase agreement with Entergy-Vermont Yankee, the owner of the Vermont Yankee nuclear plant, and VYNPC purchases 83 percent of the total output of the plant. Under the VY PPA, we purchase our entitlement share of the output of the plant, which is 29 percent of the total plant output. We have evaluated our equity investment and the power purchase agreement with VYNPC under the FASB variable interest accounting guidance and have determined that they both represent variable interests. We are not considered the primary beneficiary of VYNPC; therefore, are not required to consolidate VYNPC because we do not control the activities that are most relevant to the operating results of VYNPC.

We have an equity investment in and receive transmission services from Transco. The transmission services are billed under the 1991 Transmission Agreement ("VTA"). All of the Vermont utilities are parties to the VTA and the VTA requires the Vermont utilities to pay their pro-rata share of Transco's costs, including interest and a fixed rate of return on equity, less the revenues collected under the ISO-New England Open Access Transmission Tariff. We have evaluated our equity investment and the VTA with Transco under the FASB variable interest accounting guidance and have determined that both represent variable interests. We are not considered the primary beneficiary of Transco; therefore, we are not required to consolidate Transco because we do not control the activities that are most relevant to the operating results of Transco.

Our maximum exposure to loss is the amount of our equity investments in Transco and VYNPC. See Note 3 – Investments in Affiliates.

The amended guidance did not have an impact on our financial position, results of operations and cash flows. The guidance became effective for us on January 1, 2010.

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 (dollars in thousands, except share information):

	Three Months Ended September 30		**Nine Months Ended September 30**	
	2010	2009	**2010**	2009
Numerator for basic and diluted EPS:				
Net income	**$9,990**	$6,200	**$15,637**	$18,569
Dividends declared on preferred stock	**(92)**	(92)	**(276)**	(276)
Net income available for common stock	**$9,898**	$6,108	**$15,361**	$18,293
Denominators for basic and diluted EPS:				
Weighted-average basic shares of common stock outstanding	**12,516,488**	11,679,133	**12,109,796**	11,647,626
Dilutive effect of stock options	**11,232**	14,960	**14,343**	21,004
Dilutive effect of performance shares	**18,267**	23,125	**16,052**	17,165
Weighted-average diluted shares of common stock outstanding	**12,545,987**	11,717,218	**12,140,191**	11,685,795

Outstanding stock options totaling 42,577 for the third quarter and 44,799 for the first nine months of 2010 were excluded from the diluted EPS computation because the exercise prices were above the current average market price of the common shares, as compared to options totaling 203,317 for the third quarter and 160,157 for the first nine months of 2009.

Outstanding performance shares totaling 60,723 for the third quarter and first nine months of 2010 were excluded from the diluted EPS calculation as either the performance share measures were not met or there was an antidilutive impact, as compared to shares totaling 57,075 for the third quarter and first nine months of 2009.

NOTE 3 - INVESTMENTS IN AFFILIATES

VELCO Summarized financial information for VELCO consolidated follows (dollars in thousands):

	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	**2010**	2009
Operating revenues	**$25,408**	$22,335	**$76,610**	$68,992
Operating income	**$13,231**	$11,924	**$42,218**	$36,713
Net income	**$12,622**	$10,475	**$37,592**	$31,898
Less net income attributable to non-controlling interests	**11,495**	9,063	**34,400**	27,349
Less income tax	**130**	595	**656**	1,806
Net income attributable to VELCO	**$997**	$817	**$2,536**	$2,743
Company's common stock ownership interest	47.05%	47.05%	47.05%	47.05%
Company's equity in net income	**$468**	$384	**$1,142**	$1,285

Accounts payable to VELCO were $5.1 million at September 30, 2010 and $5.6 million at December 31, 2009.

Transco Summarized financial information for Transco; also included in VELCO consolidated financial information above follows (dollars in thousands):

	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	**2010**	2009
Operating revenues	**$25,601**	$22,206	**$77,618**	$68,613
Operating income	**$13,946**	$12,520	**$44,225**	$38,520
Net income	**$13,098**	$10,677	**$39,258**	$32,300
Company's ownership interest	33.33%	32.72%	33.33%	32.72%
Company's equity in net income	**$4,861**	$3,825	**$14,559**	$11,698

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 a $5.1 million credit in the third quarter and a $2 million credit in the first nine months of 2010 and a $0.1 million charge in the third quarter and a $5.6 million charge in the first nine months of 2009. These amounts are reflected as Transmission - affiliates on our Condensed Consolidated Statements of Income. There were no accounts payable to Transco at September 30, 2010 and $0.8 million at December 31, 2009.

VYNPC Summarized financial information for VYNPC follows (dollars in thousands):

	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	**2010**	2009
Operating revenues	**$47,289**	$46,242	**$123,061**	$136,118
Operating (loss) income	**($177)**	($595)	**($1,616)**	($2,414)
Net income	**$27**	$180	**$253**	$332
Company's common stock ownership interest	58.85%	58.85%	58.85%	58.85%
Company's equity in net income	**$16**	$106	**$149**	$195

Included in VYNPC's operating revenues above are sales to us of approximately $16.5 million in the third quarter and $42.9 million in the first nine months of 2010 and $16.1 million in the third quarter and $47.5 million in the first nine months of 2009. These are included in Purchased power - affiliates on our Condensed Consolidated Statements of Income. Accounts payable to VYNPC were $5.3 million at September 30, 2010 and $5.6 million at December 31, 2009. Also see Note 13 - 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 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 September 30, 2010, we had regulatory assets of $0.9 million for Maine Yankee, $4.9 million for Connecticut Yankee and $1.7 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 third quarter and $1 million in the first nine months of 2010 and $0.3 million in the third quarter and $1 million in the first nine months of 2009. These amounts are included in Purchased power - affiliates on our Condensed Consolidated Statements of Income.

DOE Litigation: 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 ("GTCC") waste from the nuclear plants no later than January 31, 1998 in return for payments by each company into the nuclear waste fund. No fuel or GTCC waste 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 court. The remand directed the trial court to apply the acceptance rate in 1987 annual capacity reports when determining damages.

On March 6, 2009, the three companies submitted their revised statement of claimed damages for the case on remand. Maine Yankee claimed $81.7 million through 2002, Connecticut Yankee claimed $39.7 million and Yankee Atomic claimed $53.9 million in damages through 2001.

The trial phase of the remanded case occurred in August 2009. Post-trial briefing was completed in early November 2009, and final arguments were heard on December 10, 2009.

A final ruling in favor of the three companies was issued on September 7, 2010. Maine Yankee was awarded $81.7 million, Connecticut Yankee was awarded $39.7 million and Yankee Atomic was awarded $21.2 million. The parties have 30 days to file motions for reconsideration and 60 days to file any appeals. If no motions for reconsideration are filed, the deadline for appeals will be November 8, 2010. Interest on the judgments does not start to accrue until all appeals have been decided or all appeal periods have expired with no appeals being filed. Our share of the claimed damages of $3.2 million is based on our ownership percentages described above.

The Court of Federal Claims' original decision 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 additional claims against the DOE for unspecified damages incurred for periods subsequent to the original case discussed above. On July 1, 2009, in a notification to the DOE, Maine Yankee, Connecticut Yankee and Yankee Atomic filed their claimed costs for damages. Maine Yankee claimed $43 million since January 1, 2003 and Connecticut Yankee and Yankee Atomic claimed $135.4 million and $86.1 million, respectively since January 1, 2002. For all three companies the damages were claimed through December 31, 2008.

Due to the complexity of these issues and the potential for further appeals, the three companies cannot predict the timing of the final determinations 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.

NOTE 4 - FINANCIAL INSTRUMENTS
The estimated fair values of financial instruments follow (dollars in thousands):

	September 30, 2010		December 31, 2009	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Power contract derivative assets (includes current portion)	**$2,689**	**$2,689**	$622	$622
Power contract derivative liabilities (includes current portion)	**$0**	**$0**	$368	$368
Preferred stock subject to mandatory redemption (includes current portion)	**$0**	**$0**	$1,000	$1,000
Long-term debt:				
First mortgage bonds (includes current portion)	**$167,500**	**$195,693**	$167,500	$186,210
Revenue bonds	**$10,800**	**$10,800**	$10,800	$10,800
Credit facility borrowings	**$0**	**$0**	$23,311	$23,311

At September 30, 2010, there were no unrealized losses recorded as liabilities on the Condensed Consolidated Balance Sheet and unrealized gains of $2.7 million were recorded as assets on the Condensed Consolidated Balance Sheet. At December 31, 2009, the fair values were unrealized losses of $0.4 million that were recorded as liabilities on the Consolidated Balance Sheet and unrealized gains of $0.6 million that were recorded as assets on the Consolidated Balance Sheet. For a discussion of the valuation techniques used for power contract derivatives see Note 5 - Fair Value - Power-related Derivatives below.

The fair values of our first mortgage bonds are estimated based on quoted market prices for the same or similar issues with similar remaining time to maturity or on current rates offered to us. Fair values are estimated to meet disclosure requirements and do not necessarily represent the amounts at which obligations would be settled.

The table above does not include cash, special deposits, receivables and payables. The carrying values approximate fair value because of the short duration of those instruments. Also, the carrying values of our revenue bonds approximate fair value since the rates are adjusted at least monthly. The carrying value of our credit facility borrowings approximate fair value since the rates can change daily. The fair value of our cash equivalents and restricted cash are included in Note 5 - Fair Value.

NOTE 5 - FAIR VALUE
We recognize certain assets and liabilities at fair value on our Condensed Consolidated Balance Sheets. The FASB 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."

Valuation Techniques Fair value is not an entity-specific measurement, but a market-based measurement utilizing assumptions market participants would use to price the asset or liability. The FASB requires three valuation techniques to be used at initial recognition and subsequent measurement of an asset or liability:

Market Approach: This approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.

Income Approach: This approach uses valuation techniques to convert future amounts (cash flows, earnings) to a single present value amount.

Cost Approach: This approach is based on the amount currently required to replace the service capacity of an asset (often referred to as the "current replacement cost").

The valuation technique (or a combination of valuation techniques) utilized to measure fair value is the one that is appropriate given the circumstances and for which sufficient data is available. Techniques must be consistently applied, but a change in the valuation technique is appropriate if new information is available.

Fair Value Hierarchy FASB guidance 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 and directly held securities in our non-qualified Millstone Decommissioning Trust Fund.

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 securities not directly held 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 instruments include derivatives related to our forward energy purchases and sales, financial transmission rights and a power-related option contract. There were no changes to our Level 3 fair value measurement methodologies.

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 September 30, 2010			
Assets:	**Level 1**	**Level 2**	**Level 3**	**Total**
Millstone decommissioning trust fund				
Investments in securities:				
Marketable equity securities	**$1,428**	**$2,502**		**$3,930**
Marketable debt securities				
Corporate bonds		**323**		**323**
U.S. Government issued debt securities (Agency and Treasury)		**986**		**986**
State and municipal		**13**		**13**
Other		**30**		**30**
Total marketable debt securities	**0**	**1,352**	**0**	**1,352**
Cash equivalents and other		**37**		**37**
Total investments in securities	**1,428**	**3,891**	**0**	**5,319**
Cash equivalents	**1,798**			**1,798**
Restricted cash				**0**
Power-related derivatives - current			**2,689**	**2,689**
Total assets	**$3,226**	**$3,891**	**$2,689**	**$9,806**
Liabilities:				
Power-related derivatives - current				**$0**
Power-related derivatives - long term				**0**
Total liabilities	**$0**	**$0**	**$0**	**$0**

	Fair Value as of December 31, 2009			
Assets:	Level 1	Level 2	Level 3	Total
Millstone decommissioning trust fund				
Investments in securities:				
Marketable equity securities	$1,382	$2,427		$3,809
Marketable debt securities				
Corporate bonds		328		328
U.S. Government issued debt securities (Agency and Treasury)		889		889
State and municipal		14		14
Other		4		4
Total marketable debt securities		1,235		1,235
Cash equivalents and other	2	36		38
Total investments in securities	1,384	3,698		5,082
Cash equivalents	746			746
Restricted cash	5,369			5,369
Power-related derivatives - current			$622	622
Total assets	$7,499	$3,698	$622	$11,819
Liabilities:				
Power-related derivatives - current			$219	$219
Power-related derivatives - long term			149	149
Total liabilities	$0	$0	$368	$368

Millstone Decommissioning Trust Our primary valuation technique to measure the fair value of our nuclear decommissioning trust investments is the market approach. An actively traded quoted price cannot be obtained for the qualified decommissioning fund. However, actively traded quoted prices for the underlying securities comprising the fund have been obtained. Due to these observable inputs, fixed income, equity and cash equivalent securities in the qualified fund are classified as Level 2. Equity securities are held directly in our non-qualified trust and actively traded quoted prices for these securities have been obtained. Due to these observable inputs, these equity securities are classified as Level 1.

We recognize transfers in and out of the fair value hierarchy levels at the end of the reporting period. There were no transfers of equity and debt securities within the fair value hierarchy levels during the period ended September 30, 2010.

Cash Equivalents and Restricted Cash The market approach is used to measure the fair values of money market funds included in cash equivalents and restricted cash. We have the ability to transact our money market funds at the net asset value price per share and can withdraw those funds without a penalty. We are able to obtain actively traded quoted prices for these funds; therefore they are classified as Level 1. Cash equivalents are included in cash and cash equivalents on the Condensed Consolidated Balance Sheets.

Power-related Derivatives We have three types of derivative assets and liabilities: forward energy contracts, Financial Transmission Rights ("FTRs"), and a power-related option contract ("Hydro-Québec Sellback #3"). Our primary valuation technique to measure the fair value of these derivative assets and liabilities is the income approach, which involves determining a present value amount based on estimated future cash flows. However, when circumstances warrant, we may also use alternative approaches as described below to calculate the fair value for each type of derivative. Since many of the valuation inputs are not observable in the market, we have classified our derivative assets and liabilities as Level 3.

To calculate the fair value of our forward energy contracts, we use a mark-to-market valuation model that includes the following inputs: contract energy prices, forward energy prices, contract volumes and delivery dates, risk-free and credit-adjusted interest rates, counterparty credit ratings and our credit rating.

To calculate the fair value of our FTR contracts we use two different approaches. For FTR contracts entered into with an auction date close to the reporting date, we use the auction clearing prices obtained from ISO-New England, which represents a market approach to determining fair value. Auction clearing prices are used to value all FTRs at December 31 each year. For FTR contract valuations performed at interim reporting dates, we use an internally developed valuation model to estimate the fair values for the remaining portions of annual FTRs. This model includes the following inputs: historic congestion component prices for the applicable locations, historic energy prices, forward energy prices, contract volumes and durations, and the applicable risk-free rate.

To calculate the fair value of our power-related option contract, we use a binomial tree model that includes the following inputs: forward energy prices, expected volatility, contract volume, prices and duration, and LIBOR swap rates.

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

	Three Months Ended September 30		**Nine Months Ended September 30**	
	2010	2009	**2010**	2009
Balance at beginning of period	**$2,829**	$3,659	**$254**	$8,820
Gains and losses (realized and unrealized)				
Included in earnings	**289**	4,511	**2,408**	18,110
Included in Regulatory and other assets/liabilities	**(106)**	(214)	**2,536**	(5,309)
Purchases, sales, issuances and net settlements	**(323)**	(4,546)	**(2,509)**	(18,211)
Balance as of September 30	**$2,689**	$3,410	**$2,689**	$3,410

During the three and nine months ended September 30, 2010 and 2009, 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 Sheets, depending on whether the change in fair value is an unrealized loss or gain. The corresponding offsets are current and long-term assets or liabilities depending on the duration.

NOTE 6 - INVESTMENT SECURITIES

Millstone Decommissioning Trust Fund We have decommissioning trust fund investments related to our joint-ownership interest in Millstone Unit #3. The decommissioning trust fund was established pursuant to various federal and state guidelines. Among other requirements, the fund must be managed by an independent and prudent fund manager. Any gains or losses, realized and unrealized, are expected to be refunded to or collected from customers and are recorded as regulatory assets or liabilities in accordance with the FASB guidance for Regulated Operations.

An investment is impaired if the fair value of the investment is less than its cost and if management considers the impairment to be other-than-temporary. We do not have the ability to decide to hold individual equity securities in the trusts because regulatory authorities limit our ability to oversee the day-to-day management of our nuclear decommissioning trust fund investments. Therefore, we consider all equity securities held by our nuclear decommissioning trusts with fair values below their cost basis to be other-than-temporarily impaired. The FASB guidance for Investments - Debt and Equity Securities, requires impairment of debt securities if: 1) there is the intent to sell a debt security; 2) it is more likely than not that the security will be required to be sold prior to recovery; or 3) the entire unamortized cost of the security is not expected to be recovered. For the majority of the investments shown below, we own a share of the trust fund investments.

For the third quarter of 2010, we had minimal realized gains and losses. The realized losses include minimal impairments associated with our equity securities.

For the first nine months of 2010, we had less than $0.1 million of realized gains and $0.1 million of realized losses. The realized losses include $0.1 million of impairments associated with our equity securities. There were no non-credit loss impairments of our debt securities. In 2010, there were also no permanent impairments or 'credit losses' associated with our debt securities.

For the third quarter of 2009, we had $0.1 million of realized gains and less than $0.1 million of realized losses. For the first nine months of 2009, we had $0.2 million of realized gains and $0.3 million of realized losses. The realized losses include $0.2 million of impairments associated with our equity securities. In 2009, there were no permanent impairments or 'credit losses' associated with our debt securities.

The fair value of these investments is summarized below (dollars in thousands):

	As of September 30, 2010			
Security Types	**Amortized Cost**	**Unrealized Gains**	**Unrealized Losses**	**Estimated Fair Value**
Marketable equity securities	**$3,053**	**$877**	**$0**	**$3,930**
Marketable debt securities				
Corporate bonds	**294**	**29**		**323**
U.S. Government issued debt securities (Agency and Treasury)	**910**	**76**		**986**
State and municipal	**12**	**1**		**13**
Other	**30**			**30**
Total marketable debt securities	**1,246**	**106**		**1,352**
Cash equivalents and other	**37**			**37**
Total	**$4,336**	**$983**	**$0**	**$5,319**

Security Types	As of December 31, 2009 Amortized Cost	Unrealized Gains	Unrealized Losses	Estimated Fair Value
Marketable equity securities	$3,107	$702	$0	$3,809
Marketable debt securities				
Corporate bonds	317	15	(4)	328
U.S. Government issued debt securities (Agency and Treasury)	850	44	(5)	889
State and municipal	13	1		14
Other	4			4
Total marketable debt securities	1,184	60	(9)	1,235
Cash equivalents and other	38			38
Total	$4,329	$762	($9)	$5,082

Information related to the fair value of debt securities at September 30, 2010 follows (dollars in thousands):

	Fair value of debt securities at contractual maturity dates				
	Less than 1 year	**1 to 5 years**	**5 to 10 years**	**After 10 years**	**Total**
Debt Securities	$46	$357	$292	$657	$1,352

At September 30, 2010, the fair value of debt securities in an unrealized loss position was minimal. At December 31, 2009, the fair value of debt securities in an unrealized loss position was $0.3 million.

NOTE 7 - 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.

Alternative Regulation Plan I: On September 30, 2008, the PSB issued an order approving our alternative regulation plan. The plan became effective on November 1, 2008. It expires on December 31, 2011, but we have petitioned for an extension through December, 2013. The plan 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 ("ESAM" adjustment). Under the plan, the allowed return on equity will be adjusted annually to reflect one-half of the change in the average yield on the 10-year Treasury note as measured over the last 20 trading days prior to October 15 of each year. The ESAM 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 customers in a future period. If the actual return on equity of our regulated business falls between 75 and 125 basis points below the allowed return on equity, the shortfall is shared equally between shareholders and customers. Any earnings shortfall in excess of 125 basis points below the allowed return on equity is fully recovered from customers. As such, the minimum return for our regulated business is 100 basis points below the allowed return. These adjustments are made at the end of each fiscal year.

On December 31, 2009, the PSB issued its order approving our 2010 base rate filing, which increased rates 5.58 percent, effective for bills rendered beginning January 1, 2010. The allowed rate of return for 2010, calculated in accordance with the plan, is 9.59 percent.

On February 2, 2010, the PSB held a prehearing conference, followed by a workshop, to consider the proposal to amend the non-power cost cap formula of our alternative regulation plan to allow for full cost recovery for new initiatives arising after the effective date of the plan. The DPS supported the proposal, and the 2010 base rate filing increase approved by the PSB included recovery of costs for two new initiatives. On September 3, 2010, the PSB approved the implementation of a new initiatives adder under our alternative regulation plan. In order to qualify for treatment as a new initiative the following criteria must be met: 1) the risk associated with implementing the new initiative is of a nature that is distinct from the ordinary business risk that we assume in discharging our public service obligation, and 2) the costs associated with implementing the new initiative are material. In our 2010 base rate filing we were allowed recovery of $0.2 million for a new initiative that does not meet the PSB criteria. This money will be returned to customers as part of our 2011 base rate filing.

Under the exogenous effects provisions of our alternative regulation plan, we are allowed to defer the unexpected impacts, to the extent these costs exceed $0.6 million, of changes in GAAP, tax laws, FERC or ISO-NE rules and major unplanned operation and maintenance costs, such as those due to storms. In the third quarter of 2010, we deferred $3.6 million of costs related to two major storms and tax law changes. We plan to file with the PSB by May 1, 2011, for recovery of these costs over a 12-month period, commencing on July 1, 2011.

The PCAM adjustment for the third quarter of 2010 was an over-collection of less than $0.1 million and was recorded as a current liability. This over-collection will be returned to customers over the three months ending March 31, 2011. We filed a PCAM report, including supporting documentation, with the PSB identifying this over-collection. The PSB has not yet acted on this filing.

The PCAM adjustment for the second quarter of 2010 was an under-collection of $1 million and was recorded as a current asset. We filed a PCAM report, including supporting documentation, with the PSB identifying this under-collection. The DPS recommended the PCAM report be approved as filed and the PSB accepted the DPS recommendation and approved the filing. This under-collection will be recovered from customers over the three months ending December 31, 2010.

The PCAM adjustment for the first quarter of 2010 was an over-collection of $0.5 million and was recorded as a current liability. We filed a PCAM report, including supporting documentation, with the PSB identifying this over-collection. The DPS recommended the PCAM report be approved as filed and the PSB accepted the DPS recommendation and approved the filing. This over-collection was returned to customers over the three months ending September 30, 2010.

The PCAM adjustments for 2009 were calculated to be over-collections of $0.6 million in the first quarter, $0.5 million in the second quarter, $0.6 million in the third quarter and $1 million in the fourth quarter. These over-collections were recorded as current liabilities. We filed PCAM reports, including supporting documentation, each quarter with the PSB identifying the over-collections. In each case, the DPS recommended the PCAM report be approved as filed and the PSB accepted the DPS recommendation and approved the filing. The 2009 over-collections were returned to customers over the three months ended September 30, 2009, December 31, 2009, March 31, 2010 and June 30, 2010, respectively.

On May 1, 2010, we filed our 2009 ESAM calculation using the methodology specified in our alternative regulation plan. The 2009 return on equity from the regulated portion of our business was 9.87 percent. No ESAM adjustment was required in 2009 since this return was within 75 basis points of our 2009 allowed return on equity of 9.77 percent.

On November 1, 2010, we submitted two versions of a base rate filing for the rate year commencing January 1, 2011. The first, reflecting the requested amendments to our alternative regulation plan discussed below, proposes an increase in base rates of $24.4 million or an 8.34 percent increase in retail rates. Under our alternative regulation plan, the annual change in the non-power costs, as reflected in our base rate filing, is limited to any increase in the U.S. Consumer Price Index for the northeast, less a 1 percent productivity adjustment. The non-power costs associated with the implementation of our Asset Management Plan and our CVPS SmartPower™ project are excluded from the non-power cost cap. Our 2011 non-power costs did not exceed the non-power cost cap. The second version, which follows the existing plan, proposes an increase in base rates of $21.8 million or 7.44 percent, reflecting an allowed ROE of 9.18 percent as a result of the existing ROE adjustment formula. If the proposed amendments to our alternative regulation plan are not approved by December 31, 2010, the second version of the base rate filing will become effective on January 1, 2011 unless suspended by the PSB. If the proposed amendments are subsequently approved by the PSB, the proposed rates in the first version could take effect at any time in 2011. We cannot predict the outcome of this matter at this time.

Alternative Regulation Plan II: On June 30, 2010, we filed a required Alternative Regulation Plan Analysis of Plan Performance with the PSB. This analysis evaluated the effectiveness of the Plan's performance in achieving the goals of Vermont alternative regulation. As described in the evaluation, the implementation of the current plan has helped to advance these goals; however, we also identified concerns and impediments that limit its overall effectiveness in satisfying all of the objectives of Vermont alternative regulation.

To address these concerns, on July 6, 2010 we petitioned the PSB to approve changes to the current plan to: a) extend its duration; b) alter the methodology for implementing the non-power cost cap; and c) reset the allowed ROE as noted above to 10.22 percent. If these changes are approved, the revised plan will expire on December 31, 2013 and the allowed ROE will be reset as of January 1, 2011. Thereafter, the existing annual ROE adjustment methodology would apply for the duration of the plan. Negotiations to settle are ongoing but if an agreement cannot be reached, the PSB has established a schedule for resolution of the docket including technical hearings and the filing of final legal briefs during the first quarter of 2011.

Staffing Level Investigation On February 13, 2009, the PSB opened an investigation into the staffing levels of the company as requested by us and the DPS.

On November 30, 2009, we filed a Memorandum of Understanding ("Staffing MOU") with the PSB setting forth agreements that we reached with the DPS regarding the PSB's investigation into our staffing levels. Under the Staffing MOU, in lieu of retaining a management consultant to perform a comprehensive review of our organizational structure and staffing, we and the DPS have agreed that we will reduce our staffing levels over a five-year period by a total of 17 positions as compared to the 549 positions we had on January 1, 2009. This reduction shall be in addition to the staffing changes contemplated by the implementation of CVPS SmartPower™. We retain discretion in how to achieve the staffing reductions, and the DPS has agreed that it shall not oppose the recovery in rates of all reasonable costs associated with staffing and related compensation during the term of the Staffing MOU, provided that recovery of such costs is otherwise consistent with normal ratemaking standards. Nothing in the Staffing MOU precludes us from seeking to add staff as reasonably necessary in response to new requirements imposed by the state or federal government.

On March 31, 2010, the PSB approved the Staffing MOU. The Staffing MOU allows CVPS to recover all reasonable costs associated with the staff reductions in accordance with our new initiatives amendment to the non-power cost cap formula of our alternative regulation plan. As discussed above, for these costs to qualify as a new initiative under the plan they would need to meet the criteria established by the PSB.

CVPS SmartPower™ On October 27, 2009, the DOE announced that Vermont's electric utilities will receive $69 million in federal stimulus funds to deploy advanced metering, new customer service enhancements and grid automation. As a participant on Vermont's smart grid stimulus application, we expect to receive a grant of over $31 million. The agreement includes provisions for funding and other requirements.

The agreement was executed on April 15, 2010 and became effective on April 19, 2010. We are eligible to receive reimbursement of 50 percent of our total project cost incurred since August 6, 2009, up to $31 million. Through September 30, 2010, we incurred $3.5 million of costs, of which $1.9 million were operating expenses and $1.6 million were capital expenditures. We have submitted requests for reimbursement of $1.7 million and have received $1 million to date.

On April 7, 2010, we filed a Memorandum of Understanding ("CVPS SmartPower™ MOU") with the PSB, which included, among other things, the agreement we reached with the DPS on the recovery of costs we will incur due to CVPS SmartPower™ implementation. We received the PSB's order approving the cost recovery principles contained in the CVPS SmartPower™ MOU on August 6, 2010. On September 3, 2010, the PSB recognized the CVPS SmartPower™ plan as an authorized initiative under the new initiative adder discussed above.

Our current rates include the recovery of costs that are eligible for government grant reimbursement by the United States Department of Energy ("DOE") under the American Recovery and Reinvestment Act; however, the grant reimbursement is not reflected in our current rates. Grant reimbursements are recorded to a regulatory liability until they are reflected in rates.

Regulatory Accounting Under FASB's guidance for regulated operations, 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 for accounting for regulated operations and there is not a rate mechanism to recover these costs, we would be required to write off $13.5 million of regulatory assets (total regulatory assets of $46 million less pension and postretirement medical costs of $32.5 million), $4.5 million of other deferred charges - regulatory and $6.8 million of other deferred credits - regulatory. This would result in a total charge to operations of $11.2 million on a pre-tax basis as of September 30, 2010. We would be required to record pre-tax pension and postretirement costs of $31.9 million to Accumulated Other Comprehensive Loss and $0.5 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. Regulatory assets, certain other deferred charges and other deferred credits are shown in the table below (dollars in thousands).

	September 30, 2010	December 31, 2009
Regulatory assets		
Pension and postretirement medical costs	**$32,470**	$32,033
Nuclear plant dismantling costs	**7,467**	8,498
Nuclear refueling outage costs - Millstone Unit #3	**648**	269
Income taxes	**4,550**	4,389
Asset retirement obligations and other	**827**	1,051
Total Regulatory assets	**$45,962**	$46,240
Other deferred charges - regulatory		
Vermont Yankee sale costs (tax)	**673**	673
Unrealized losses on power-related derivatives	**0**	368
ESAM deferred costs	**3,554**	0
Utility acquisition costs	**96**	0
Other	**176**	503
Total Other deferred charges - regulatory	**$4,499**	$1,544
Other deferred credits - regulatory		
Asset retirement obligation - Millstone Unit #3	**2,623**	2,497
Vermont Yankee settlements	**0**	183
Unrealized gains on power-related derivatives	**2,655**	488
Smart Grid	**958**	0
Other	**550**	720
Total Other deferred credits - regulatory	**$6,786**	$3,888

The regulatory assets included in the table above are being recovered in retail rates and are supported by written rate orders. The recovery period for regulatory assets varies based on the nature of the costs. All regulatory assets are earning a return, except for income taxes, nuclear plant dismantling costs, and pension and postretirement medical costs. Other deferred charges - regulatory are supported by PSB-approved accounting orders or approved cost recovery methodologies, allowing cost deferral until recovery in a future rate proceeding. Most items listed in other deferred credits - regulatory are being amortized for periods ranging from two to three years. Pursuant to PSB-approved rate orders, when a regulatory asset or liability is fully amortized, the corresponding rate revenue shall be booked as a reverse amortization in an opposing regulatory liability or asset account.

Regulatory assets for pension and postretirement medical costs are discussed in Note 11 - Pension and Postretirement Medical Benefits. Regulatory assets for nuclear plant dismantling costs are related to our equity interests in Maine Yankee, Connecticut Yankee and Yankee Atomic, which are described in Note 3 - Investments in Affiliates. Power-related derivatives are discussed in more detail in Note 5 - Fair Value and Note 10 - Power-related Derivatives.

NOTE 8 - COMMON STOCK
On November 6, 2009, we filed a Registration Statement with the Securities and Exchange Commission ("SEC") on Form S-3, requesting the ability to offer, from time to time and in one or more offerings, up to $55 million of our common stock. On December 4, 2009, the SEC declared the Registration Statement to be effective. On January 15, 2010, we filed a Prospectus Supplement with the SEC, noting that we entered into an equity distribution agreement that allowed us to issue up to $45 million of shares under an "at-the-market" program. As of September 30, 2010, 848,057 shares of our common stock have been issued, yielding net proceeds of $17.1 million.

NOTE 9 - LONG-TERM DEBT AND CREDIT FACILITY
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 that expires on November 2, 2011. It contains financial and non-financial covenants. 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 and power contract performance assurance requirements, in the form of funds borrowed and letters of credit. At September 30, 2010, $5.5 million in letters of credit and no borrowings were outstanding under this credit facility.

We also have a 364-day, $15 million unsecured revolving credit facility with a different lending institution pursuant to a credit agreement dated December 30, 2009 that expires on December 29, 2010. The purpose of and our obligation under this credit agreement are the same as described above. At September 30, 2010, there were no borrowings or letters of credit outstanding under this credit facility.

Current Portion of long-term debt: In June 2010, we reclassified $20 million of long-term debt to current portion of long-term debt on the Condensed Consolidated Balance Sheet. Our First Mortgage Bonds Series SS are due in June 2011.

Covenants: Our long-term debt indentures, letters of credit, credit facilities and articles of association contain financial covenants. The most restrictive financial covenants include maximum debt to total capitalization of 65 percent, and minimum mortgage bond interest coverage of 2.0 times. At September 30, 2010, we were in compliance with all financial covenants related to our various debt agreements, articles of association, letters of credit, credit facilities and material agreements.

NOTE 10 - POWER-RELATED DERIVATIVES
We are exposed to certain risks in 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 entered into one forward power sale contract for 2010 and one forward power sale contract in 2011 to reduce the price volatility of our net power costs. Deliveries under the 2010 sale contract are excused during any period of time that Vermont Yankee is not operating as a result of an unplanned outage; otherwise we are required to sell the stated volumes in the contract. We have concluded that the 2010 forward power sale contract is a derivative contract. Sales volumes under the 2011 forward sale contract will vary according to changes in Vermont Yankee's output and we have concluded that the 2011 forward power sale contract is not a derivative.

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. Our power supply forecast shows that in 2012, our load requirements will exceed our energy purchase and production amounts, as certain committed long-term power purchase contracts begin to expire.

On August 12, 2010, we executed a significant long-term power purchase contract with H.Q. Energy Services (U.S.) Inc., ("HQUS") and we have concluded that this contract meets the "normal purchase, normal sale" exception to derivatives accounting. We have excluded the fair value of this contract from power-related derivatives on the balance sheet. For additional information on this contract, see Note 13 - Commitments and Contingencies - New Hydro-Québec Agreement.

Several years ago, we entered into the Hydro-Québec Sellback #3 contract, a long-term purchased power contract that allows the seller to repurchase specified amounts of power with advance notice. The option under this contract will expire by the end of 2010. 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.

Outstanding power-related derivative contracts are as follows:

	MWh (000s)	
	September 30, 2010	**December 31, 2009**
Commodity		
Forward Energy Contracts	167.8	517.3
Financial Transmission Rights	524.3	2067.9
Hydro-Quebec Sellback #3	136.9	136.9

We recognized the following amounts in the Condensed Consolidated Statements of Income in connection with derivative financial instruments (dollars in thousands):

	Three months ended September 30		**Nine months ended September 30**	
	2010	2009	**2010**	2009
Net realized gains (losses) reported in operating revenues	**$284**	$4,538	**$2,984**	$18,195
Net realized gains (losses) reported in purchased power	**5**	(27)	**(576)**	(85)
Net realized gains (losses) reported in earnings	**$289**	$4,511	**$2,408**	$18,110

Realized gains and losses on derivative instruments are conveyed to or recovered from customers through the PCAM and have no impact on results of operations. Derivative transactions and related collateral requirements are included in net cash flows from operating activities in the Condensed Consolidated Statements of Cash Flows. 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. We have no derivative instruments with credit-risk-related contingent features that were in a liability position on September 30, 2010. For information concerning performance assurance, see Note 13 - Commitments and Contingencies - Performance Assurance.

NOTE 11 - PENSION AND POSTRETIREMENT MEDICAL BENEFITS

The fair value of Pension Plan trust assets was $103.9 million at September 30, 2010 and $97.2 million at December 31, 2009. The unfunded accrued pension benefit obligation recorded on the Condensed Consolidated Balance Sheets was $18.6 million at September 30, 2010 and $19.8 million at December 31, 2009.

The fair value of Postretirement Plan trust assets was $18.2 million at September 30, 2010 and $15 million at December 31, 2009. The unfunded accrued postretirement benefit obligation recorded on the Condensed Consolidated Balance Sheets was $12 million at September 30, 2010, and $13.8 million at December 31, 2009.

Components of net periodic benefit costs follow (dollars in thousands):

Pension Benefits	Three months ended September 30		Nine months ended September 30	
	2010	2009	**2010**	2009
Service cost	**$1,026**	$946	**$3,078**	$2,838
Interest cost	**1,754**	1,652	**5,262**	$4,956
Expected return on plan assets	**(2,063)**	(2,077)	**(6,189)**	($6,231)
Amortization of net actuarial loss	**0**	0	**0**	$0
Amortization of prior service cost	**107**	86	**321**	$258
Net periodic benefit cost	**824**	607	**2,472**	1,821
Less amounts capitalized	**187**	91	**505**	231
Net benefit costs expensed	**$637**	$516	**$1,967**	$1,590

Postretirement Benefits	Three months ended September 30		Nine months ended September 30	
	2010	2009	**2010**	2009
Service cost	**$228**	$178	**$684**	$534
Interest cost	**395**	428	**1,185**	1,284
Expected return on plan assets	**(301)**	(196)	**(903)**	(588)
Amortization of net actuarial loss	**242**	379	**726**	1,137
Amortization of transition (asset) obligation	**64**	64	**192**	192
Amortization of prior service cost	**70**	70	**210**	210
Net periodic benefit cost	**698**	923	**2,094**	2,769
Less amounts capitalized	**159**	139	**428**	351
Net benefit costs expensed	**$539**	$784	**$1,666**	$2,418

Investment Strategy Our pension investment policy seeks to achieve sufficient growth to enable the Pension Plan to meet our future benefit obligations to participants, maintain certain funded ratios and minimize near-term cost volatility. Current guidelines specify generally that 54 percent of plan assets be invested in equity securities and 46 percent of plan assets be invested in debt securities. The debt securities are comprised of long-duration bonds to match changes in plan liabilities.

Our postretirement medical benefit plan investment policy seeks to achieve sufficient funding levels to meet future benefit obligations to participants and minimize near-term cost volatility. Current guidelines specify generally that 60 percent of the plan assets be invested in equity securities and 40 percent be invested in debt securities. Fixed-income securities are of a shorter duration to better match the cash flows of the postretirement medical obligation.

Trust Fund Contributions In July 2010, we contributed $3.3 million to the pension trust fund and $2.7 million to the postretirement medical trust funds. We do not plan to make any additional contributions to these trust funds in 2010. In June 2009, we contributed $2.4 million to the pension trust fund and $3.8 million to the postretirement medical trust funds.

NOTE 12 - INCOME TAXES

Health Care Legislation: On March 23, 2010, the federal Patient Protection and Affordable Care Act ("the Act") was signed into law. The Act is a comprehensive health care reform bill that includes revenue-raising provisions for nearly $400 billion over 10 years through tax increases on high-income individuals, excise taxes on high-cost group health plans, and new fees on selected health-care-related industries. In addition, on March 25, 2010, the Health Care and Education Affordability Reconciliation Act of 2010 was passed into law, which modifies certain provisions of the Act.

Together, the legislation repeals the current rule permitting a tax deduction for prescription drug coverage expense under our postretirement medical plan that is actuarially equivalent to that provided under Medicare Part D. This provision is effective for taxable years beginning after December 31, 2012. As required, in March 2010 we recorded an increase of $2.1 million in regulatory assets and an increase of $2.8 million in deferred income taxes liabilities on the Condensed Consolidated Balance Sheets, resulting in an increase of $0.7 million in income tax expense on the Condensed Consolidated Statements of Income, related to postretirement medical expenditures that will not be deductible in the future.

The Act also had an additional unfavorable impact on the effective income tax rate for 2010. As a result of the elimination of the tax deduction in 2010, we were not able to recognize approximately $0.5 million of income tax benefits in the first nine months of 2010.

The Act is considered an exogenous event and is included in the exogenous effects deferral. See Note 7 – Retail Rates and Regulatory Accounting for additional information.

Bonus Depreciation: As a result of the Small Business Jobs Acts of 2010, extending an income tax benefit for bonus depreciation to 2010, we recorded $3.9 million to prepayments and deferred income tax liabilities on the Condensed Consolidated Balance Sheets.

Capitalized Repairs Project: The Capitalized Repairs Project included the review of 1999 through 2009 property, plant and equipment additions included in Utility Plant on the Condensed Consolidated Balance Sheets. The review was performed to identify capitalized additions, which now result in accelerated income tax deductions. Since these deductions are only temporary timing differences, they do not affect total income tax expense or the effective tax rate. In the third quarter of 2010, as a result of our Capitalized Repairs Project, we recorded $11.5 million to prepayments and deferred income tax liabilities on the Condensed Consolidated Balance Sheets.

Uncertain Tax Positions: Concurrent with the entries arising from the capitalized repairs deductions, in the third quarter of 2010, we recorded $3.2 million of unrecognized tax benefits, which partially offset the amounts described above for the Capitalized Repairs Project.

NOTE 13 - COMMITMENTS AND CONTINGENCIES

Long-Term Power Purchases *Vermont Yankee:* We are purchasing our entitlement share of Vermont Yankee plant output through the VY PPA between Entergy-Vermont Yankee and VYNPC, discussed above. VYNPC's entitlement to plant output is 83 percent and our share of plant output is 29 percent; our nominal entitlement is approximately 180 MW. We have one secondary purchaser that receives less than 0.5 percent of our entitlement.

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 plant normally shuts down for about one month every 18 months for maintenance and to insert new fuel into the reactor. A refueling outage was completed in May 2010 and estimated incremental costs for replacement power were factored into our 2010 base rates.

Our total VYNPC purchases were $16.5 million in the third quarter and $42.9 million in the first nine months of 2010 and $16.1 million in the third quarter and $47.5 million in the first nine months of 2009.

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 March 22, 2010 through March 21, 2011. This outage insurance does not apply to derates 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 hourly spot market price and $42/MWh. The aggregate maximum coverage is $9 million with a $1.2 million deductible.

On June 22, 2010, we, along with Green Mountain Power Corporation ("GMP"), made a claim under the September 6, 2001 VY PPA. The claim is that Entergy-Vermont Yankee breached its obligations under the agreement by failing to detect and remedy the conditions that resulted in cooling tower-related failures at the Vermont Yankee nuclear plant in 2007 and 2008. Those failures caused us and GMP to incur substantial replacement power costs.

We are seeking recovery of the incremental costs from Entergy-Vermont Yankee under the terms of the VY PPA based upon the results of certain reports, including an 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 to seek recovery, we also reviewed the 2007 and 2008 root cause analysis reports by Entergy-Vermont Yankee and a December 22, 2008 reliability assessment provided by Nuclear Safety Associates to the State of Vermont. Entergy-Vermont Yankee disputes our claim. We cannot predict the outcome of this matter at this time.

The VY PPA contains a formula for determining the VYNPC power entitlement following an uprate in 2006 that increased the plant's operating capacity by approximately 20 percent. 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 VY 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 VY PPA. We cannot predict the outcome of this matter at this time.

Our contract for power purchases from VYNPC ends in March 2012, but there is a risk that we could lose this resource if the plant shuts down for any reason before that date. An early shutdown could cause our customers 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 forward market prices as of September 30, 2010, the incremental replacement cost of lost power is estimated to average $8.2 million annually over the remaining life of the contract. We are not able to predict whether there will be an early shutdown of the Vermont Yankee plant or whether the PSB would allow timely and full recovery of increased costs related to such shutdown. An early shutdown, depending upon the specific circumstances, could involve cost recovery via the outage insurance described above and recoveries under the PCAM but, in general, would not be expected to materially impact financial results if the costs are recovered in retail rates in a timely fashion.

Entergy-Vermont Yankee has submitted a renewal application with the NRC and an application for a Certificate of Public Good ("CPG") with the PSB 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. Significant hurdles may prevent its relicensing. Potential operating, transparency and communication issues related to the plant have raised serious concerns among regulators and members of the Vermont Legislature, including some who have called for its temporary or permanent shutdown. An intervenor in the CPG case has requested that the PSB order a shutdown of the Vermont Yankee plant due to recent leaks at the site. The PSB has opened a new docket to consider that request. We are unable to predict the outcome of this matter.

On February 24, 2010, in a non-binding vote, the Vermont Senate voted against allowing the PSB to consider granting the Vermont Yankee plant another 20-year operating license after 2012. The new Vermont Legislature elected on November 2, 2010 could vote differently, although the political makeup of the House and Senate remains largely unchanged. Also, Vermont elected a new governor who advocated as a member of the Vermont Senate and during the gubernatorial campaign that the Vermont Yankee Plant should close when its current license expires. While circumstances could change and we expect to engage in a constructive dialogue with the new administration and legislature related to the continued operation of the Vermont Yankee Plant, we are unable to predict the outcome at this time.

Entergy-Vermont Yankee is attempting to overcome these concerns, and in April 2010, we began a new round of negotiations on a new contract. We rejected Entergy-Vermont Yankee's last public proposal, but both parties continue to exchange information and proposals. The parties are attempting to negotiate a purchased power contract in order that the state will have the value of such an agreement to consider should the other 20-year extension issues that have emerged be resolved. We cannot predict the outcome of this matter at this time.

Hydro-Québec: We are purchasing power from Hydro-Québec 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-Québec, 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 under the current contract decreases by approximately 19 percent after 2012, and by approximately 84 percent after 2015. Our total purchases under the VJO Power contract were $15.7 million in the third quarter and $47.4 million in the first nine months of 2010 and $15.7 million in the third quarter and $47.9 million in the first nine months of 2009.

The annual load factor is 75 percent for the remainder of the VJO Power Contract, unless the contract is changed or there is a reduction due to the adverse hydraulic conditions described below.

There are two sellback contracts with provisions that apply to existing and future VJO Power Contract purchases. The first resulted in the sellback of 25 MW of capacity and associated energy through April 30, 2012, which has no net impact currently since an identical 25 MW purchase was made in conjunction with the sellback. We have a 23 MW share of the 25 MW sellback. However, since the sellback ends nine months before the corresponding purchase ends, the first sellback will result in a 23 MW increase in our capacity and energy purchases for the period from May 1, 2012 through October 1, 2012.

A second sellback contract provided benefits to us that ended in 1996 in exchange for two options to Hydro-Québec. The first option gives Hydro-Québec 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-Québec 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-Québec 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-Québec, the remaining VJO participants will "step-up" to the defaulting party's share on a pro-rata basis. As of September 30, 2010, our obligation is about 47 percent of the total VJO Power Contract through 2016, and represents approximately $300.3 million, on a nominal basis.

In accordance with FASB's guidance for guarantees, 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 contract in its most recent rate applications. Despite the remote chance that such an event could occur, we estimate that our undiscounted purchase obligation would be an additional $352 million for the remainder of the contract, assuming that all members of the VJO defaulted by October 1, 2010 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 or biomass as fuel. Most of the power comes through a state-appointed purchasing agent that allocates power to all Vermont utilities under PSB rules. Our total purchases from IPPs were $3.9 million in the third quarter and $16.1 million in the first nine months of 2010 and $4.8 million in the third quarter of 2009 and $16.5 million in the first nine months of 2009.

Future Power Agreements *New Hydro-Québec Agreement:* On August 12, 2010 we, along with Green Mountain Power Corporation ("GMP"), Vermont Public Power Supply Authority ("VPPSA"), Vermont Electric Cooperative, Inc. ("VEC"), Vermont Marble Power Division of Omya Industries Inc. ("Vermont Marble"), Town of Stowe Electric Department ("Stowe"), City of Burlington, Vermont Electric Department ("BED"), Washington Electric Cooperative, Inc. ("WEC") and the 13 municipal members of VPPSA (collectively, the "Buyers") entered into an agreement for the purchase of shares of 218 MW to 225 MW of energy and environmental attributes from HQUS commencing on November 1, 2012 and continuing through 2038.

The rights and obligations of the Buyers under this long-term power purchase and sale agreement with HQUS ("HQUS PPA"), including payment of the contract price and indemnification obligations, are several and not joint or joint and several. Therefore, we shall have no responsibility for the obligations, financial or otherwise, of any other party to the HQUS PPA. The parties have also entered into related agreements, including collateral agreements between each Buyer and HQUS, a Hydro-Québec guaranty, an allocation agreement among the Buyers, and an assignment and assumption agreement between us and Vermont Marble, related to the pending acquisition.

The HQUS PPA will replace approximately 65 percent of the existing VJO Power Contract discussed above, which along with the VY PPA supply the majority of Vermont's current power needs. The VJO Power Contract and the VY PPA expire within the next several years.

The obligations of HQUS and each Buyer are contingent upon the receipt of certain governmental approvals. On August 17, 2010, the Buyers filed a petition with the PSB asking for Certificates of Public Good under Section 248 of Title 30, Vermont Statutes Annotated. The PSB has established a schedule for the docket including technical hearings and final legal briefs in the first quarter of 2011. In the event the HQUS PPA is terminated with respect to any Buyer as a result of such Buyer's failure to receive governmental approvals, each of the other Buyers will have an option to purchase the additional energy.

Under the Agreement, subject to regulatory approval, we would be entitled to purchase an energy quantity of up to 85.4 MW from November 1, 2015 to October 31, 2016; 96.4 MW from November 1, 2016 to October 31, 2020; 98.4 MW from November 1, 2020 to October 31, 2030; 112.1 MW from November 1, 2030 to October 31, 2035; and 26.7 MW from November 1, 2035 to October 31, 2038.

Other Future Power Agreements: As we continue to build and diversify our power portfolio as planned and to comply with state law which establishes goals for including renewable power in our mix, we have recently signed several agreements for clean and competitively priced renewable energy. On September 9, 2010 we agreed to purchase output from Iberdrola Renewables' planned Deerfield Wind Project. We will purchase 20 MW of the project's planned output for nine years.

Other recently signed agreements include: two separate agreements to purchase 30.3 percent of the actual output from Granite Reliable Wind project for 20 years beginning April 1, 2011 and an additional 20 percent for 15 years beginning in November 2012; an agreement to purchase the entire 4.99 MW output of Ampersand Gilman Hydro for five years starting April 1, 2012; and 15 MW of around-the-clock energy from J.P. Morgan Ventures Energy for the calendar years 2013 through 2015.

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 Millstone Unit #3 decommissioning costs. Dominion Nuclear Connecticut has suspended contributions to the Millstone Unit #3 Trust Fund because the minimum NRC funding requirements have been 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 is 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 and completely decommissioned except for the spent fuel storage at each location. Our obligations related to these plants are described in Note 3 - Investments in Affiliates.

We also had a 35 percent ownership interest in the Vermont Yankee nuclear power plant through our equity investment in VYNPC, but the plant was sold in 2002. Our obligation for plant decommissioning costs ended when the plant was sold, except that VYNPC retained responsibility for the pre-1983 spent fuel disposal cost liability. VYNPC has a dedicated Trust Fund that meets most of the liability. Changes in the underlying interest rates that affect the earnings and the liability could cause the balance to be a surplus or deficit. Excess funds, if any, will be returned to us and the other former owners and must be applied to the benefit of retail customers.

DOE Litigation We have a 1.7303 joint-ownership percentage in Millstone Unit #3, in which Dominion Nuclear Connecticut ("DNC") is the lead owner with 93.4707 percent of the plant joint-ownership. In January 2004 DNC filed, on behalf of itself and the two minority owners, including us, a lawsuit against the DOE seeking recovery of costs related to the storage of spent nuclear fuel arising from the failure of the DOE to comply with its obligations to commence accepting such fuel in 1998. A trial commenced in May 2008. On October 15, 2008, the United States Court of Federal Claims issued a favorable decision in the case, including damages specific to Millstone Unit #3. The DOE appealed the court's decision in December 2008. On February 20, 2009, the government filed a motion seeking an indefinite stay of the briefing schedule. On March 18, 2009, the court granted the government's request to stay the appeal. On November 19, 2009, DNC filed a motion to lift the stay. On April 12, 2010, the stay was lifted and a staggered briefing schedule was proposed, to which DNC has responded with a request to expedite the briefing schedule so that the appeals of all parties can be heard concurrently.

On June 30, 2010, the DOE filed its initial brief in the spent fuel damages litigation. This brief focuses on the costs awarded in connection with Millstone Unit #3. DNC replied to the government's brief in August, 2010. The government's reply brief was filed September 14, 2010 and briefing on the appeal is now complete. It is expected that the court will schedule oral argument thereafter, with a decision on the appeal to follow.

We continue to pay our share of the DOE Spent Fuel assessment expenses levied on actual generation and will share in recovery from the lawsuit, if any, in proportion to our ownership interest.

Performance Assurance We are subject to performance assurance requirements through ISO-New England under the Financial Assurance Policy for NEPOOL members. At our current investment-grade credit rating, we have a credit limit of $2.9 million with ISO-New England. We are required to post collateral for all net purchased power transactions in excess of this credit limit. 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 September 30, 2010, we had posted $6.9 million of collateral under performance assurance requirements for certain of our power contracts, of which $5.5 million was in the form of a letter of credit and $1.4 million was represented by cash and cash equivalents. At December 31, 2009, we had posted $5.4 million of collateral under performance assurance requirements for certain of our power contracts, all of which 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.

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 ("EPA"). 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.

The total reserve for environmental matters was $1.1 million as of September 30, 2010 and $1.6 million as of December 31, 2009. The reserve for environmental matters is included as current and long-term liabilities on the Condensed Consolidated Balance Sheets and represents our best estimate of the cost to remedy issues at these sites based on available information as of the end of the applicable reporting periods. Below is a brief discussion of the significant 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 ("PCB") 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 June 2010 both the Vermont Agency of Natural Resources ("VT ANR") and the EPA approved separate remediation work plans for the manufactured gas plant and PCB waste at the site. Remedial work started in August 2010. We have reviewed our reserve for this site based on a 2006 cost estimate of remediation and determined that it is adequate. The liability for site remediation is expected to range from $0.9 million to $2.3 million. Remediation is ongoing and as of September 30, 2010, we have accrued $0.4 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. We have reviewed our reserve for this site based on a 2006 cost estimate of remediation and determined that it is adequate. The liability for site remediation is expected to range from $0.1 million to $1.3 million. As of September 30, 2010, we have accrued $0.5 million representing the most likely remaining cost of the remediation effort.

Currently, the Windham Regional Commission and the Town of Brattleboro are pursuing the redevelopment of the gas plant site and waterfront area into vehicle parking with green space. This concept calls for the removal of the remnant gas plant building plus covering and otherwise avoiding contaminated areas instead of removing contaminated soil and debris. We are assessing the cost implications of this conceptual plan. Currently we do not believe the impact of the plan will be material.

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 we paid based on completion of PSNH's cleanup effort. As of September 30, 2010, our remaining obligation was less than $0.1 million.

Other: In December 2009, we voluntarily submitted results of internally tested soil samples from two additional locations to the State of Vermont Sites Management Section ("SMS"). These soil sample results showed contamination at levels of concern to SMS. As a result, SMS listed these sites as active hazardous waste sites. As of September 30, 2010 we had a reserve of $0.1 million.

To management's knowledge, there is no pending or threatened litigation regarding other sites with the potential to cause material expense. No government agency has sought funds from us for any other study or remediation.

Catamount Indemnifications On December 20, 2005, we completed the sale of Catamount, our wholly owned subsidiary, to CEC Wind Acquisition, LLC, a company established by Diamond Castle Holdings, a New York-based private equity investment firm ("Diamond Castle"). 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.

Leases and support agreements
Operating Leases: We have two master lease agreements for vehicles and related equipment. On October 30, 2009, we signed a vehicle lease agreement to finance many of the vehicles covered by a former agreement. Our guarantee obligation under this lease will not exceed 8 percent of the acquisition cost. The maximum amount of future payments under this guarantee at September 30, 2010 is approximately $0.4 million. The total future minimum lease payments required for all lease schedules under this agreement at September 30, 2010 is $4 million. The maximum amount approved for lease under this agreement is $5.5 million, of which $5.3 million was outstanding at September 30, 2010.

On October 24, 2008, we entered into an operating lease for new vehicles and other related equipment. Our guarantee obligation under this lease is limited to 5 percent of the acquisition cost. The maximum amount of future payments under this guarantee is approximately $0.1 million. The total future minimum lease payments required for all lease schedules under this agreement at September 30, 2010 is $2.3 million. The total acquisition cost of all lease additions under this agreement at September 30, 2010 is $2.9 million. The maximum amount available for lease additions in 2010 under this agreement is $4 million, of which $0.3 million has been added at September 30, 2010.

Customer Bankruptcy On October 26, 2009, a major telecommunications customer filed for bankruptcy protection. As of September 30, 2010, our accounts receivable includes an estimate of the net realizable amount. In May 2010, a settlement agreement was reached; however, it is subject to court approval. On June 28, 2010, the PSB rejected the bankruptcy plan; therefore, this could delay the court's approval of the plan and final settlement. We are unable to predict the outcome of this matter, or its impact on our financial statements, at this time.

Legal Proceedings We are involved in legal and administrative proceedings in the normal course of business. We do not believe that the ultimate outcome of these proceedings will have a material adverse effect on our financial position, results of operations or cash flows.

NOTE 14 - PENDING ACQUISITIONS
On April 30, 2010, we signed a purchase and sale agreement with Omya, Inc. to purchase certain generating, transmission and distribution assets of its Vermont Marble Power Division ("VMPD") located in the State of Vermont. Under this agreement, we will pay $33.2 million for the transmission and distribution assets and generating assets comprised of four hydroelectric generating stations. The agreement contains usual and customary purchase and sale terms and conditions and is contingent upon federal and state regulatory approvals.

With Omya, Inc., we filed a joint petition with the PSB on August 2, 2010, requesting that they consent to the proposed sale by Omya and purchase by CVPS of assets used in the public service business of VMPD and approve certain related matters. As part of the proposed purchase and sale, we will acquire from VMPD, among other things, four hydroelectric facilities on Otter Creek and VMPD's transmission and distribution facilities, which include approximately 56 miles of 46 kV transmission lines, 11 miles of 2.4/4.16 kV distribution lines, one distribution substation in the Village of Proctor, and two transmission substations. On September 14, 2010, the PSB held a prehearing conference and subsequently established a schedule for resolution of the docket including technical hearings and the filing of final legal briefs during the first quarter of 2011.

On October 28, 2010, we received approval from FERC, subject to certain conditions, for the proposed transaction.

NOTE 15 - SEGMENT REPORTING

Our reportable operating segments include: **Central Vermont Public Service Corporation ("CV - VT")**, represents our principal utility operations, which engages in the purchase, production, transmission, distribution and sale of electricity in Vermont. East Barnet is included with CV- VT in the table below. **Other Companies** represents our non-utility operations and consists of Catamount Resources Corporation ("CRC"), Eversant Corporation, ("Eversant"), and C.V. Realty, Inc. CRC was formed to hold our subsidiaries that invest in unregulated business opportunities and is the parent company of Eversant, which engages in the sale and rental of electric water heaters in Vermont and New Hampshire through its wholly owned subsidiary, SmartEnergy Water Heating Services, Inc. C.V. Realty, Inc. is a real estate company whose purpose is to own, acquire, buy, sell and lease real and personal property and interests.

The following table provides segment financial data for the three and nine months ended September 30 (dollars in thousands). Inter-segment revenues were a nominal amount in all periods presented.

	CV VT	Other Companies	Reclassification & Consolidating Entries	Consolidated
Three Months Ended				
September 30, 2010				
Revenues from external customers	**$85,392**	**$438**	**($438)**	**$85,392**
Net income	**$9,921**	**$69**	**$0**	**$9,990**
Total assets at September 30	**$643,964**	**$2,581**	**($248)**	**$646,297**
September 30, 2009				
Revenues from external customers	$81,791	$446	($446)	$81,791
Net income	$5,948	$252	$0	$6,200
Total assets at December 31	$630,103	$2,356	($307)	$632,152
Nine Months Ended				
September 30, 2010				
Revenues from external customers	**$256,336**	**$1,306**	**($1,306)**	**$256,336**
Net income	**$15,456**	**$181**	**$0**	**$15,637**
Total assets at September 30	**$643,964**	**$2,581**	**($248)**	**$646,297**
September 30, 2009				
Revenues from external customers	$255,145	$1,298	($1,298)	$255,145
Net income	$18,204	$365	$0	$18,569
Total assets at December 31	$630,103	$2,356	($307)	$632,152

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 are based on, and should be read in conjunction with, the accompanying Condensed Consolidated Financial Statements. The discussion below also includes non-U.S. 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-U.S. GAAP measure should not be considered as an alternative to our consolidated fully diluted earnings per share determined in accordance with U.S. 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," "may", "will", "should", "project", "plan", "seek", "intend" or similar expressions or the negative thereof 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 alternative regulation;
- liquidity requirements;
- the 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;
- the performance of other parties in joint projects, including other Vermont utilities and Transco;
- our ability to successfully manage a number of projects involving new and evolving technology;
- 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. A more detailed assessment of the risks that could cause actual results to materially differ from current expectations is contained in the "Risk Factors" section of our Annual Report on Form 10-K for the year ended December 31, 2009.

EXECUTIVE SUMMARY

Our core business is the Vermont electric utility business. The rates we charge for retail electricity sales are regulated by the 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 alternative regulation plan that we proposed in August 2007, with modifications. This plan provides more timely adjustments to power, operating and maintenance costs, which better serves the interests of customers and shareholders.

Our consolidated earnings for the third quarter of 2010 were $10 million, or 79 cents per diluted share of common stock, and $15.6 million, or $1.27 cents per diluted share of common stock, for the first nine months. This compares to consolidated earnings of $6.2 million, or 52 cents per diluted share of common stock for the third quarter, and $18.6 million, or $1.57 per diluted share of common stock, for the first nine months of 2009. The primary drivers of the third quarter year-over-year earnings variance are described in Results of Operations below.

Major Storm: A major winter storm knocked out power to more than 91,000 of our retail customers throughout our service territory in February 2010. The cost of this storm is $3.1 million, making it one of the five most-expensive storms in our history. In May 2010, a second major storm resulted in service restoration costs of $1.2 million. Our rates include a five-year average of storm restoration costs, but given the magnitude of these major storms, that average will not fully recover our current costs. Any incremental service restoration costs above the level currently reflected in our retail rates may be deferred throughout the year for recovery through the earnings sharing adjustment mechanism ("ESAM" adjustment) and exogenous effects provisions of our alternative regulation plan.

Health Care Legislation: In March 2010, the federal Patient Protection and Affordable Care Act and the Health Care and Education Affordability Reconciliation Act of 2010 were passed into law. Together, the legislation required us to record $0.7 million of additional income tax expense related to postretirement medical costs. Also, see Recent Accounting Pronouncements below for additional information.

Exogenous Effects: As a result of the major storm and health care legislation items described above, we deferred $3.6 million of costs in the third quarter of 2010. See Retail Rates and Alternative Regulation below for additional information.

New Hydro-Québec Agreement: On August 12, 2010 we, along with Green Mountain Power Corporation ("GMP"), Vermont Public Power Supply Authority ("VPPSA"), Vermont Electric Cooperative, Inc. ("VEC"), Vermont Marble Power Division of Omya Industries Inc. ("Vermont Marble"), Town of Stowe Electric Department ("Stowe"), City of Burlington, Vermont Electric Department ("BED"), Washington Electric Cooperative, Inc. ("WEC") and the 13 municipal members of VPPSA (collectively, the "Buyers") entered into an agreement for the purchase of shares of 218 MW to 225 MW of energy and environmental attributes from H.Q. Energy Services (U.S.) Inc. ("HQUS") commencing on November 1, 2012 and continuing through 2038. For more information on this agreement, see Power Supply Matters below.

Financial Initiatives: Our financial initiatives include maintaining sufficient liquidity to support ongoing operations, the dividend on our common stock and investments in our electric utility infrastructure; planning for replacement power when our long-term power contracts expire; and evaluating opportunities to further invest in Transco. Continued focus on these financial initiatives is critical to maintaining our corporate credit rating.

We discuss these financial initiatives and the risks facing our business in more detail below.

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.

Alternative Regulation Plan I: On September 30, 2008, the PSB issued an order approving our alternative regulation plan. The plan became effective on November 1, 2008. It expires on December 31, 2011, but we have petitioned for an extension through December, 2013. The plan 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 ("ESAM" adjustment). Under the plan, the allowed return on equity will be adjusted annually to reflect one-half of the change in the average yield on the 10-year Treasury note as measured over the last 20 trading days prior to October 15 of each year. The ESAM 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 customers in a future period. If the actual return on equity of our regulated business falls between 75 and 125 basis points below the allowed return on equity, the shortfall is shared equally between shareholders and customers. Any earnings shortfall in excess of 125 basis points below the allowed return on equity is fully recovered from customers. As such, the minimum return for our regulated business is 100 basis points below the allowed return. These adjustments are made at the end of each fiscal year.

On December 31, 2009, the PSB issued its order approving our 2010 base rate filing, which increased rates 5.58 percent, effective for bills rendered beginning January 1, 2010. The allowed rate of return for 2010, calculated in accordance with the plan, is 9.59 percent.

On February 2, 2010, the PSB held a prehearing conference, followed by a workshop, to consider the proposal to amend the non-power cost cap formula of our alternative regulation plan to allow for full cost recovery for new initiatives arising after the effective date of the plan. The DPS supported the proposal, and the 2010 base rate filing increase approved by the PSB included recovery of costs for two new initiatives. On September 3, 2010, the PSB approved the implementation of a new initiatives adder under our alternative regulation plan. In order to qualify for treatment as a new initiative the following criteria must be met: 1) the risk associated with implementing the new initiative is of a nature that is distinct from the ordinary business risk that we assume in discharging our public service obligation, and 2) the costs associated with implementing the new initiative are material. In our 2010 base rate filing we were allowed recovery of $0.2 million for a new initiative that does not meet the PSB criteria. This money will be returned to customers as part of our 2011 base rate filing.

Under the exogenous effects provisions of our alternative regulation plan, we are allowed to defer the unexpected impacts, to the extent these costs exceed $0.6 million, of changes in GAAP, tax laws, FERC or ISO-NE rules and major unplanned operation and maintenance costs, such as those due to storms. In the third quarter of 2010, we deferred $3.6 million of costs related to two major storms and tax law changes. We plan to file with the PSB by May 1, 2011, for recovery of these costs over a 12-month period, commencing on July 1, 2011.

The PCAM adjustment for the third quarter of 2010 was an over-collection of less than $0.1 million and was recorded as a current liability. This over-collection will be returned to customers over the three months ending March 31, 2011. We filed a PCAM report, including supporting documentation, with the PSB identifying this over-collection. The PSB has not yet acted on this filing.

The PCAM adjustment for the second quarter of 2010 was an under-collection of $1 million and was recorded as a current asset. We filed a PCAM report, including supporting documentation, with the PSB identifying this under-collection. The DPS recommended the PCAM report be approved as filed and the PSB accepted the DPS recommendation and approved the filing. This under-collection will be recovered from customers over the three months ending December 31, 2010.

The PCAM adjustment for the first quarter of 2010 was an over-collection of $0.5 million and was recorded as a current liability. We filed a PCAM report, including supporting documentation, with the PSB identifying this over-collection. The DPS recommended the PCAM report be approved as filed and the PSB accepted the DPS recommendation and approved the filing. This over-collection was returned to customers over the three months ending September 30, 2010.

The PCAM adjustments for 2009 were calculated to be over-collections of $0.6 million in the first quarter, $0.5 million in the second quarter, $0.6 million in the third quarter and $1 million in the fourth quarter. These over-collections were recorded as current liabilities. We filed PCAM reports, including supporting documentation, each quarter with the PSB identifying the over-collections. In each case, the DPS recommended the PCAM report be approved as filed and the PSB accepted the DPS recommendation and approved the filing. The 2009 over-collections were returned to customers over the three months ended September 30, 2009, December 31, 2009, March 31, 2010 and June 30, 2010, respectively.

On May 1, 2010, we filed our 2009 ESAM calculation using the methodology specified in our alternative regulation plan. The 2009 return on equity from the regulated portion of our business was 9.87 percent. No ESAM adjustment was required in 2009 since this return was within 75 basis points of our 2009 allowed return on equity of 9.77 percent.

On November 1, 2010, we submitted two versions of a base rate filing for the rate year commencing January 1, 2011. The first, reflecting the requested amendments to our alternative regulation plan discussed below, proposes an increase in base rates of $24.4 million or an 8.34 percent increase in retail rates. Under our alternative regulation plan, the annual change in the non-power costs, as reflected in our base rate filing, is limited to any increase in the U.S. Consumer Price Index for the northeast, less a 1 percent productivity adjustment. The non-power costs associated with the implementation of our Asset Management Plan and our CVPS SmartPower™ project are excluded from the non-power cost cap. Our 2011 non-power costs did not exceed the non-power cost cap. The second version, which follows the existing plan, proposes an increase in base rates of $21.8 million or 7.44 percent, reflecting an allowed ROE of 9.18 percent as a result of the existing ROE adjustment formula. If the proposed amendments to our alternative regulation plan are not approved by December 31, 2010, the second version of the base rate filing will become effective on January 1, 2011 unless suspended by the PSB. If the proposed amendments are subsequently approved by the PSB, the proposed rates in the first version could take effect at any time in 2011. We cannot predict the outcome of this matter at this time.

Alternative Regulation Plan II: On June 30, 2010, we filed a required Alternative Regulation Plan Analysis of Plan Performance with the PSB. This analysis evaluated the effectiveness of the Plan's performance in achieving the goals of Vermont alternative regulation. As described in the evaluation, the implementation of the current plan has helped to advance these goals; however, we also identified concerns and impediments that limit its overall effectiveness in satisfying all of the objectives of Vermont alternative regulation.

To address these concerns, on July 6, 2010 we petitioned the PSB to approve changes to the current plan to: a) extend its duration; b) alter the methodology for implementing the non-power cost cap; and c) reset the allowed ROE as noted above to 10.22 percent. If these changes are approved, the revised plan will expire on December 31, 2013 and the allowed ROE will be reset as of January 1, 2011. Thereafter, the existing annual ROE adjustment methodology would apply for the duration of the plan. Negotiations to settle are ongoing but if an agreement cannot be reached, the PSB has established a schedule for resolution of the docket including technical hearings and the filing of final legal briefs during the first quarter of 2011.

Staffing Level Investigation On February 13, 2009, the PSB opened an investigation into the staffing levels of the company as requested by us and the DPS.

On November 30, 2009, we filed a Memorandum of Understanding ("Staffing MOU") with the PSB setting forth agreements that we reached with the DPS regarding the PSB's investigation into our staffing levels. Under the Staffing MOU, in lieu of retaining a management consultant to perform a comprehensive review of our organizational structure and staffing, we and the DPS have agreed that we will reduce our staffing levels over a five-year period by a total of 17 positions as compared to the 549 positions we had on January 1, 2009. This reduction shall be in addition to the staffing changes contemplated by the implementation of CVPS SmartPower™. We retain discretion in how to achieve the staffing reductions, and the DPS has agreed that it shall not oppose the recovery in rates of all reasonable costs associated with staffing and related compensation during the term of the Staffing MOU, provided that recovery of such costs is otherwise consistent with normal ratemaking standards. Nothing in the Staffing MOU precludes us from seeking to add staff as reasonably necessary in response to new requirements imposed by the state or federal government.

On March 31, 2010, the PSB approved the Staffing MOU. The Staffing MOU allows CVPS to recover all reasonable costs associated with the staff reductions in accordance with our new initiatives amendment to the non-power cost cap formula of our alternative regulation plan. As discussed above, for these costs to qualify as a new initiative under the plan they would need to meet the criteria established by the PSB.

CVPS SmartPower™ On October 27, 2009, the DOE announced that Vermont's electric utilities will receive $69 million in federal stimulus funds to deploy advanced metering, new customer service enhancements and grid automation. As a participant on Vermont's smart grid stimulus application, we expect to receive a grant of over $31 million. The agreement includes provisions for funding and other requirements.

The agreement was executed on April 15, 2010 and became effective on April 19, 2010. We are eligible to receive reimbursement of 50 percent of our total project cost incurred since August 6, 2009, up to $31 million. Through September 30, 2010, we incurred $3.5 million of costs, of which $1.9 million were operating expenses and $1.6 million were capital expenditures. We have submitted requests for reimbursement of $1.7 million and have received $1 million to date.

On April 7, 2010, we filed a Memorandum of Understanding ("CVPS SmartPower™ MOU") with the PSB, which included, among other things, the agreement we reached with the DPS on the recovery of costs we will incur due to CVPS SmartPower™ implementation. We received the PSB's order approving the cost recovery principles contained in the CVPS SmartPower™ MOU on August 6, 2010. On September 3, 2010, the PSB recognized the CVPS SmartPower™ plan as an authorized initiative under the new initiative adder discussed above.

Our current rates include the recovery of costs that are eligible for government grant reimbursement by the United States Department of Energy ("DOE") under the American Recovery and Reinvestment Act; however, the grant reimbursement is not reflected in our current rates. Grant reimbursements are recorded to a regulatory liability until they are reflected in rates.

LIQUIDITY, CAPITAL RESOURCES AND COMMITMENTS

Cash Flows At September 30, 2010, we had cash and cash equivalents of $3.9 million compared to $10.3 million at September 30, 2009. The primary components of cash flows from operating, investing, and financing activities for both periods are discussed in more detail below.

Our primary sources of cash in 2010 were from our electric utility operations, proceeds from our revolving credit facility, proceeds from the issuance of common stock, refunds of income taxes and distributions received from affiliates. Our primary uses of cash in 2010 included capital expenditures for utility operations, utility operating expenses, common and preferred dividend payments, repayments of borrowings under our revolving credit facility and interest expense.

Operating Activities: Operating activities provided $38 million in the first nine months of 2010, compared to $33.3 million in the same period of 2009. The increase of $4.7 million was due to a number of items. The $7.1 million favorable variance in cash requirements for power collateral is mostly resulting from replacing purchased power cash collateral with a letter of credit and the decrease of $0.5 million related to employee benefit plan funding is due to lower benefit costs in 2010. In the first nine months of 2010, we received net income tax refunds of $4.5 million compared to net income tax refunds of $2.1 million in the first nine months of 2009. Tax refunds during both years primarily related to our elections for federal bonus depreciation. These items were primarily offset by a decrease of $8.8 million in resale sales in the first nine months as a result of reduced contract rates for resale power sales, a decrease of $4.7 million from increased storm costs and a decrease of $2.9 million resulting from planned outages at the Vermont Yankee and Millstone Unit #3 nuclear plants.

Our accounts receivable over 60 days from retail customers were $2.1 million at September 30, 2010 and $2.5 million at December 31, 2009, a decrease of 16 percent.

Investing Activities: Investing activities used $21.6 million in the first nine months of 2010 compared to $21.9 million in the same period of 2009, and there were no significant variances among the uses year over year. The majority of the construction and plant expenditures were for system reliability, performance improvements and customer service enhancements.

Financing Activities: Financing activities used $14.5 million in the first nine months of 2010, compared to $7.8 million in the same period of 2009. The $6.7 million increase in the amount used was primarily due to $23.3 million of higher net repayments of borrowings under our revolving credit facility in 2010, partially offset by $17.2 million of net proceeds, primarily from our at-the-market common stock issuance program through September 30, 2010.

Transco Based on current projections, Transco expects to need additional equity capital from 2010 through 2014, 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, which are subject to available capital and appropriate regulatory approvals, we continue to evaluate investment opportunities on a case-by-case basis. We are currently considering additional investments of approximately $21.9 million in 2010, $28.6 million in 2011, $43.8 million in 2012, $56.9 million in 2013 and $0 in 2014, but the timing and amounts depend on the factors discussed above and the amounts invested by other owners.

We are currently evaluating debt and equity issuance alternatives to fund these investments, but any investments that we make in Transco are voluntary, and subject to available capital and appropriate regulatory approvals. These capital investments in Transco and our core business provide value to customers and shareholders alike. They provide shareholders with a return on investment while helping to maintain and improve reliability for our customers.

Pending Acquisitions On April 30, 2010, we signed a purchase and sale agreement with Omya, Inc. to purchase certain generating, transmission and distribution assets of its Vermont Marble Power Division ("VMPD") located in the State of Vermont. Under this agreement, we will pay $33.2 million for the transmission and distribution assets and generating assets comprised of four hydroelectric generating stations. The agreement contains usual and customary purchase and sale terms and conditions and is contingent upon federal and state regulatory approvals.

With Omya, Inc., we filed a joint petition with the PSB on August 2, 2010, requesting that they consent to the proposed sale by Omya and purchase by CVPS of assets used in the public service business of VMPD and approve certain related matters. As part of the proposed purchase and sale, we will acquire from VMPD, among other things, four hydroelectric facilities on Otter Creek and VMPD's transmission and distribution facilities, which include approximately 56 miles of 46 kV transmission lines, 11 miles of 2.4/4.16 kV distribution lines, one distribution substation in the Village of Proctor, and two transmission substations. On September 14, 2010, the PSB held a prehearing conference and subsequently established a schedule for resolution of the docket including technical hearings and the filing of final legal briefs during the first quarter of 2011.

On October 28, 2010, we received approval from FERC, subject to certain conditions, for the proposed transaction.

Dividends Our dividend level is reviewed by our Board of Directors on a quarterly basis. It is our goal to ensure earnings in future years are sufficient to maintain our current dividend level.

Dividend Reinvestment Plan Our Dividend Reinvestment Plan used Treasury shares as the source of common shares to meet reinvestment obligations since July 2007. These elections resulted in additional cash flow of $1 million to $2 million annually. In September 2009, we ceased using Treasury shares and began using original issue shares to meet reinvestment obligations under the plan.

Customer Bankruptcy On October 26, 2009, a major telecommunications customer filed for bankruptcy protection. As of September 30, 2010, our accounts receivable include an estimate of the net realizable amount. In May 2010, a settlement agreement was reached; however, it is subject to court approval. On June 28, 2010, the PSB rejected the bankruptcy plan; therefore, this could delay the court's approval of the plan and final settlement. We are unable to predict the outcome of this matter, or its impact on our financial statements, at this time.

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 and $15 million unsecured revolving credit facilities to fund our business over the next few years. Prolonged 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. An extended Vermont Yankee plant outage could involve cost recovery via our forced outage insurance policy and recoveries under the PCAM but in general would not be expected to materially impact our financial results, if the costs are recovered in retail rates in a timely fashion. 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. It is important to note, however, that our alternative regulation plan sets bands around the earnings in our regulated business, which ensures, in part, that they will not fall below prescribed levels. See Retail Rates and Alternative Regulation above for additional information related to mechanisms designed to mitigate our utility-related risks. See Retail Rates and Alternative Regulation above for additional information related to mechanisms designed to mitigate our utility-related risks.

Global Economic Conditions We expect to have access to liquidity in the capital markets when needed at reasonable rates. We have access to a $40 million unsecured revolving credit facility and a $15 million unsecured revolving credit facility with two different lending institutions. However, sustained turbulence in the global credit markets could limit or delay our access to capital. As part of our enterprise risk management program, we routinely monitor our risks by reviewing our investments in and exposure to various firms and financial institutions.

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 that expires on November 2, 2011. It contains financial and non-financial covenants. 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 and power contract performance assurance requirements, in the form of funds borrowed and letters of credit. At September 30, 2010, $5.5 million in letters of credit and no borrowings were outstanding under this credit facility. We did have periodic borrowings under this facility during the quarter.

We also have a 364-day, $15 million unsecured revolving credit facility with a different lending institution pursuant to a credit agreement dated December 30, 2009 that expires on December 29, 2010. The purpose and obligation under this credit agreement are the same as described above. At September 30, 2010, there were no borrowings or letters of credit outstanding under the credit facility and through September 30, 2010, and we have not used this facility for borrowings or letters of credit. We expect to renew this credit facility for three years in the fourth quarter of 2010.

Covenants: Our long-term debt indentures, letters of credit, credit facilities and articles of association contain financial covenants. The most restrictive financial covenants include maximum debt to total capitalization of 65 percent, and minimum mortgage bond interest coverage of 2.0 times. At September 30, 2010, we were in compliance with all financial covenants related to our various debt agreements, articles of association, letters of credit, credit facilities and material agreements.

Common Equity Issue: On November 6, 2009, we filed a Registration Statement with the SEC on Form S-3, requesting the ability to offer, from time to time and in one or more offerings, up to $55 million of our common stock. On December 4, 2009, the SEC declared the Registration Statement to be effective. On January 15, 2010, we filed a Prospectus Supplement with the SEC noting that we entered into an equity distribution agreement that allowed us to issue up to $45 million of shares under an "at-the-market" program. As of September 30, 2010, there have been 848,057 shares issued, yielding net proceeds of $17.1 million.

Long-term Debt Issues: On July 15, 2010, we entered into a commitment to issue $40 million of first mortgage bonds at 5.89 percent on June 15, 2011 in a private placement transaction, pending regulatory approvals. The proceeds will be used to help finance our capital expenditures, debt retirements, investments in Transco and other corporate purposes.

We also plan to issue $30 million of tax-exempt Recovery Zone Facility Bonds through the Vermont Economic Development Authority ("VEDA"), secured by $30 million of first mortgage bonds. The bonds are expected to be issued in the fourth quarter of 2010. The proceeds will be used to fund certain capital improvements to our production, transmission, distribution and general facilities.

Capital Commitments Our business is capital-intensive because annual construction expenditures are required to maintain the distribution system. As of September 30, 2010, capital expenditures were $21 million.

Capital expenditures for the years 2011 to 2015 are expected to range from $36 million to $60 million annually, including an estimated total of more than $60 million for CVPS SmartPower™ over the five-year period. A portion of this CVPS SmartPower™ project total will be funded by the Smart Grid Stimulus Grant and this grant is reflected in the annual spending range above. Further discussion of the Smart Grid Stimulus Grant can be found above in Retail Rates and Alternative Regulation - CVPS SmartPower™.

Performance Assurance We are subject to performance assurance requirements through ISO-New England under the Financial Assurance Policy for NEPOOL members. At our current investment-grade credit rating, we have a credit limit of $2.9 million with ISO-New England. We are required to post collateral for all net purchased power transactions in excess of this credit limit. 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 September 30, 2010, we had posted $6.9 million of collateral under performance assurance requirements for certain of our power contracts, of which $5.5 million was in the form of a letter of credit and $1.4 million was represented by cash and cash equivalents. At December 31, 2009, we had posted $5.4 million of collateral under performance assurance requirements for certain of our power contracts, all of which 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.

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. We have letters of credit that are described in Financing above. Until the third quarter of 2010, we leased most vehicles and related equipment under operating lease agreements. These operating lease agreements are described in Note 13 - Commitments and Contingencies.

Commitments and Contingencies We have material power supply commitments for the purchase of power from VYNPC and Hydro-Québec. These are described in Power Supply Matters below.

We own equity interests in VELCO and Transco, which require us to pay a portion of their operating costs under our transmission agreements. We own an equity interest in VYNPC and are obligated to pay a portion of VYNPC's operating costs under a purchased power contract ("VY PPA") between VYNPC and Entergy-Vermont Yankee. We also own equity interests in three nuclear plants that have completed decommissioning. We are responsible for paying our share of the costs associated with these plants. Our equity ownership interests are described in Note 3 - Investments in Affiliates.

On December 20, 2005, we completed the sale of Catamount, our wholly owned subsidiary, to CEC Wind Acquisition, LLC, a company established by Diamond Castle Holdings, a New York-based private equity investment firm ("Diamond Castle"). Under the terms of the agreements with Catamount and Diamond Castle, we agreed to indemnify them, and certain of their respective affiliates as described in Note 13 - Commitments and Contingencies.

OTHER BUSINESS RISKS

Our Enterprise Risk Management ("ERM") program serves to protect our assets, safeguard shareholder investment, ensure compliance with applicable legal requirements and effectively serve our customers. The ERM program is intended to provide an integrated and effective governance structure for risk identification and management and legal compliance within the company. Among other things, we use metrics to assess key risks, including the potential impact and likelihood of the key risks.

We are also subject to regulatory risk and wholesale power market risk related to our Vermont electric utility business.

Regulatory Risk: Historically, electric utility rates in Vermont have been based on a utility's costs of service. Accordingly, we are entitled to charge rates that are sufficient to allow us an opportunity to recover reasonable operation and capital costs and a reasonable return on investment to attract needed capital and maintain our financial integrity, while also protecting relevant public interests. We are subject to certain accounting standards that allow regulated entities, in appropriate circumstances, to establish regulatory assets and liabilities, and thereby defer the income statement impact of certain costs and revenues that are expected to be realized in future rates. There is no assurance that the PSB will approve the recovery of all costs incurred for the operation, maintenance, and construction of our regulated assets, as well as a return on investment. Adverse regulatory changes could have a significant impact on future results of operations and financial condition. See Critical Accounting Policies and Estimates.

The State of Vermont has passed several laws since 2005 that impact our regulated business and will continue to impact it in the future. Some changes include requirements for renewable energy supplies and opportunities for alternative regulation plans. See Recent Energy Policy Initiatives below.

Power Supply Risk: 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, or due to environmental concerns. Hydro-Québec contract deliveries through our current contract end in 2016, but the average level of deliveries decreases by approximately 19 percent after 2012, and by approximately 84 percent after 2015. 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. However, we have been planning for the expiration of these contracts for several years, and a robust effort, described further below, is in place to ensure a safe, reliable, environmentally beneficial and relatively affordable energy supply going forward.

Entergy-Vermont Yankee has submitted a renewal application with the NRC and an application for a CPG with the PSB 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. Significant hurdles may prevent its relicensing. Potential operating, transparency and communication issues related to the plant have raised serious concerns among regulators and members of the Vermont Legislature, including some who have called for its temporary or permanent shutdown. An intervenor in the CPG case has requested that the PSB order a shutdown of the Vermont Yankee plant due to recent leaks at the site. The PSB has opened a new docket to consider that request.

On February 24, 2010, in a non-binding vote, the Vermont Senate voted against allowing the PSB to consider granting the Vermont Yankee plant another 20-year operating license after 2012. The new Vermont Legislature elected on November 2, 2010 could vote differently, although the political makeup of the House and Senate remains largely unchanged. Also, Vermont elected a new governor who advocated as a member of the Vermont Senate and during the gubernatorial campaign that the Vermont Yankee Plant should close when its current license expires. While circumstances could change and we expect to engage in a constructive dialogue with the new administration and legislature related to the continued operation of the Vermont Yankee Plant, we are unable to predict the outcome at this time.

Entergy-Vermont Yankee is attempting to overcome these concerns, and in April 2010, we began a new round of negotiations on a new contract. We rejected Entergy-Vermont Yankee's last public proposal, but both parties continue to exchange information and proposals. The parties are attempting to negotiate a purchased power contract in order that the state will have the value of such an agreement to consider should the other 20-year extension issues that have emerged be resolved. 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 forward market prices as of September 30, 2010, the incremental replacement cost of lost power is estimated to average $8.2 million annually over the remaining life of the contract. We are not able to predict whether there will be an early shutdown of the Vermont Yankee plant or whether the PSB would allow timely and full recovery of increased costs related to such shutdown. An early shutdown, depending upon the specific circumstances, could involve cost recovery via the outage insurance described above and recoveries under the PCAM but, in general, would not be expected to materially impact financial results, if the costs are recovered in retail rates in a timely fashion.

On November 4, 2010, Entergy announced that it will explore the potential sale of Vermont Yankee. Entergy stated that while no decision had been made to sell the plant, the company expects interest from multiple parties. We cannot predict the outcome of this matter.

Wholesale Power Market Price Risk: Our material power supply contracts are with Hydro-Québec and VYNPC. These contracts comprise the majority of our total annual energy (MWh) purchases. If one or both of these sources becomes unavailable for a period of time, there could be exposure to high wholesale power prices and that amount could be material.

We are responsible for procuring replacement energy during periods of scheduled or unscheduled outages of our power sources. Average market prices at the times when we purchase replacement energy might be higher than amounts included for recovery in our retail rates. We have forced outage insurance through March 21, 2011 to cover additional costs, if any, of obtaining replacement power from other sources if the Vermont Yankee plant experiences unplanned outages. The Power Cost Adjustment Mechanism within our alternative regulation plan allows recovery of power costs.

Market Risk: See Item 3 - Quantitative and Qualitative Disclosures About Market Risk.

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 Annual Report on Form 10-K for the year ended December 31, 2009.

Health Care Reform Legislation On March 23, 2010, the federal Patient Protection and Affordable Care Act ("the Act") was signed into law. The Act is a comprehensive health care reform bill that includes revenue-raising provisions for nearly $400 billion over 10 years through tax increases on high-income individuals, excise taxes on high-cost group health plans, and new fees on selected health-care-related industries. In addition, on March 25, 2010, the Health Care and Education Affordability Reconciliation Act of 2010 was passed into law, which modifies certain provisions of the Act.

Together, the legislation repeals the current rule permitting a tax deduction for prescription drug coverage expense under our postretirement medical plan that is actuarially equivalent to that provided under Medicare Part D. This provision is effective for taxable years beginning after December 31, 2012. As required, in March 2010 we recorded an increase of $2.1 million in regulatory assets and an increase of $2.8 million in deferred income taxes on the Condensed Consolidated Balance Sheets, resulting in an increase of $0.7 million in income tax expense on the Condensed Consolidated Statements of Income, related to postretirement medical expenditures that will not be deductible in the future.

We continue to evaluate the future impact of the legislation on our employee benefit plans; however, we are currently unable to predict the impact on our financial statements or whether we will experience any significant change in future benefit cost trends.

Other See Note 1 - Business Organization and Summary of Significant Accounting Policies to the accompanying Notes to Condensed Consolidated Financial Statements.

RESULTS OF OPERATIONS

The following is a detailed discussion of the results of operations for the third quarter and first nine months of 2010. This should be read in conjunction with the Condensed Consolidated Financial Statements and accompanying notes included in this report.

Our third quarter 2010 earnings increased $3.8 million, or 27 cents per diluted share of common stock compared to the same period in 2009. Earnings for the first nine months of 2010 decreased by $2.9 million, or 30 cents per diluted share of common stock, compared to the same period in 2009. The table that follows provides a reconciliation of the primary year-over-year variances in diluted earnings per share for 2010 versus 2009. The earnings per diluted share for each variance shown below are non-GAAP measures:

Reconciliation of Earnings Per Diluted Share

	Third Quarter 2010 vs. 2009	**First Nine Months 2010 vs. 2009**
2009 Earnings per diluted share	**$0.52**	**$1.57**
Year-over-Year Effects on Earnings:		
Higher maintenance expenses	0.00	(0.25)
Higher other operating expenses (primarily regulatory amortizations)	(0.02)	(0.21)
Higher purchased power expense	(0.17)	(0.11)
Higher taxes other than income	(0.03)	(0.09)
Lower other income, net	(0.02)	(0.08)
Health Care Reform/Medicare Part D - Income tax impact	0.00	(0.06)
Common stock issuance (April to September 2010) - 848,057 additional shares	(0.05)	(0.03)
Lower transmission expenses	0.23	0.23
Regulatory deferral - exogenous costs	0.18	0.18
Higher equity in earnings of affiliates	0.06	0.13
Higher operating revenues	0.18	0.06
Other (various items)	(0.09)	(0.07)
2010 Earnings per diluted share	**$0.79**	**$1.27**

Note: For presentation purposes in the table above, the additional average shares from the 2010 stock issuance were excluded from the 12,545,987 average shares of common stock - diluted for the third quarter and the 12,140,191 average shares of common stock - diluted for the first nine months, in order to compute the individual EPS variances and to provide comparable information for 2010 vs. 2009. The additional shares were included in the total EPS calculations.

Operating Revenues The majority of operating revenues is generated through retail electric sales. Retail sales are affected by weather and economic conditions since these factors influence customer use. Resale sales represent the sale of power into the wholesale market normally sourced from owned and purchased power supply in excess of that needed by our retail customers. The amount of resale revenue is affected by the availability of excess power for resale, the types of sales we enter into and the price of those sales. Operating revenues and related MWh sales are summarized below:

	Three months ended Sept 30				**Nine months ended Sept 30**			
	Revenues (in thousands)		**mWh Sales**		**Revenues (in thousands)**		**mWh Sales**	
	2010	**2009**	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Residential	**$36,243**	$33,100	**242,076**	229,843	**$108,718**	$102,802	**728,369**	727,559
Commercial	**29,023**	26,819	**222,655**	212,925	**82,240**	77,359	**627,342**	615,554
Industrial	**8,002**	7,668	**90,987**	90,414	**24,967**	23,954	**274,281**	272,316
Other	**498**	480	**1,645**	1,624	**1,488**	1,417	**4,874**	4,800
Total retail sales	**73,766**	68,067	**557,363**	534,806	**217,413**	205,532	**1,634,866**	1,620,229
Resale sales	**8,299**	10,188	**172,659**	190,754	**26,622**	41,252	**555,963**	639,188
Provision for rate refund	**18**	(27)	**0**	0	**2,344**	(1,128)	**0**	0
Other operating revenues	**3,309**	3,563	**0**	0	**9,957**	9,489	**0**	0
Total operating revenues	**$85,392**	$81,791	**730,022**	725,560	**$256,336**	$255,145	**2,190,829**	2,259,417

2010 vs. 2009

Operating revenues increased by $3.6 million in the third quarter and $1.2 million in the first nine months of 2010 as compared to the same periods in 2009 as a result of the following:

- Retail sales increased $5.7 million in the third quarter and $11.9 million in the first nine months resulting primarily from a 5.58 percent base rate increase effective January 1, 2010 and the recovery of 2008 major storm costs through the ESAM, in addition to a weather-related resurgence of retail load in the third quarter of 2010.
- Resale sales decreased $1.9 million in the third quarter due to lower volumes available at lower prices and $14.6 million in the first nine months mostly due to the same reason and a decrease in volumes sold due to the scheduled refueling outages at the Vermont Yankee plant and Millstone Unit #3.
- The provision for rate refund is primarily related to over- or under-collections of power, production and transmission costs as defined by the power cost adjustment clause of our alternative regulation plan.
- Other operating revenues decreased $0.3 million in the third quarter due to many small items and increased $0.5 million in the first nine months mostly from higher levels of mutual aid to other utilities in the first quarter of 2010 and the sale of renewable energy credits.

Operating Expenses Operating expenses increased $0.2 million in the third quarter and $4.8 million in the first nine months of 2010 as compared to 2009. Significant variances in operating expenses on the Condensed Consolidated Statements of Income are described below.

Purchased Power - affiliates and other: Purchased power expense and volume is summarized below:

	Three Months Ended Sept 30				Nine Months Ended Sept 30			
	Purchases (in thousands)		mWh purchases		Purchases (in thousands)		mWh purchases	
	2010	2009	**2010**	2009	**2010**	2009	**2010**	2009
VYNPC	**$16,469**	$16,104	**381,879**	387,167	**$42,858**	$47,546	**1,004,045**	1,156,940
Hydro-Quebec	**15,701**	15,657	**239,308**	223,860	**47,449**	47,871	**728,773**	699,993
Independent Power Producers	**3,899**	4,789	**31,314**	47,142	**16,056**	16,461	**135,290**	149,981
Subtotal long-term contracts	**36,069**	36,550	**652,501**	658,169	**106,363**	111,878	**1,868,108**	2,006,914
Other purchases	**4,861**	887	**40,212**	9,677	**13,716**	5,079	**146,276**	37,119
Reserve for loss on power contract	**(299)**	(299)	**0**	0	**(897)**	(897)	**0**	0
Nuclear decommissioning	**348**	330	**0**	0	**1,031**	984	**0**	0
Other	**130**	208	**0**	0	**(175)**	847	**0**	0
Total purchased power	**$41,109**	$37,676	**692,713**	667,846	**$120,038**	$117,891	**2,014,384**	2,044,033

2010 vs. 2009

Purchased power expense increased $3.4 million in the third quarter and $2.1 million in the first nine months of 2010 compared to the same periods in 2009 as a result of the following:

- Purchased power costs under long-term contracts decreased $0.5 million in the third quarter and $5.5 million in the first nine months of 2010, due primarily to lower output at the Vermont Yankee plant related to an extended scheduled refueling outage, lower capacity costs from Hydro-Québec and decreased purchases from Independent Power Producers.
- Other purchases increased $4 million in the third quarter due to higher retail load and increased volumes at higher market prices and $8.6 million in the first nine months for the same reason in addition to the purchase of replacement power for the scheduled refueling outages at Vermont Yankee and Millstone Unit #3.
- Nuclear decommissioning costs are associated with our ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. These costs are based on FERC-approved tariffs.
- Other costs decreased $0.1 million in the third quarter and $1 million in the first nine months. These Other costs are amortizations and deferrals based on PSB-approved regulatory accounting, including those 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 as well as some direct charges for facilities that we rent. Transco allocates its monthly cost of service through the Vermont Transmission Agreement ("VTA"), net of NOATT reimbursements and certain direct charges. The NOATT is the mechanism through which the costs of New England's high-voltage (so-called PTF) transmission facilities are collected from load-serving entities using the system and redistributed to the owners of the facilities, including Transco.

The decreases of $5.2 million for the third quarter and $7.6 million for the first nine months were principally due to higher NOATT reimbursements under the VTA, related to the overall transmission expansion in New England, 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 increases of $0.5 million for the third quarter and $2.9 million for the first nine months primarily resulted from higher rates and overall transmission expansion in New England.

Other operation: These expenses are related to operating activities such as customer accounting, customer service, administrative and general activities, regulatory deferrals and amortizations, and other operating costs incurred to support our core business. The decreases of $3.1 million for the third quarter and $1.1 million for the first nine months were primarily due to $1.2 million of lower net regulatory amortizations, largely due to an exogenous effects deferral entry of $3.6 million recorded in the third quarter, partially offset by increased recoveries of 2008 major storm costs, and $1 million of lower reserves for uncollectible accounts in 2010, primarily due to a customer bankruptcy in 2009. These decreases were partially offset by $1.1 million of higher employee benefit costs.

Maintenance: These expenses are associated with maintaining our electric distribution system and include costs of our jointly owned generation and transmission facilities. The increase of $5 million for the first nine months were largely due to higher service restoration costs related to major storms in February and May 2010.

Taxes other than income: This is related primarily to property taxes and payroll taxes. The increases of $0.6 million for the third quarter and $1.7 million for the first nine months were largely due to increases in property taxes.

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. The effective combined federal and state income tax rate for 2010 is 39.9 percent compared to 31.5 percent for 2009. The variance includes the impact of the Patient Protection and Affordable Care Act, as modified by the Health Care and Education Reconciliation Act, which represents 4 percent of the 2010 effective tax rate. This item is considered an exogenous event and is included in the exogenous effects deferral. See Note 12 – Income Taxes for additional information.

Other Income These items represent the non-operating activities of our utility business and the operating and non-operating activities of our non-regulated business through CRC. CRC's earnings were less than $0.1 million for the third quarter and $0.2 million for the first nine months of 2010 compared to $0.3 million in the third quarter and $0.4 million in the first nine months of 2009. Significant variances in line items that comprise other income on the Condensed Consolidated Statements of Income are described below.

Equity in earnings of affiliates: These are earnings on our equity investments including VELCO, Transco and VYNPC. The increase of $1 million for the third quarter and $2.7 million in the nine months is principally due to the $20.8 million investment that we made in Transco in December 2009.

Other Deductions: These items include supplemental retirement benefits and insurance, including changes in the cash surrender value of variable life insurance policies, non-utility expenses relating to rental water heaters, and miscellaneous other deductions. The increase of $0.3 million for the third quarter and $1 million for the first nine months is primarily related to changes in the cash surrender value of variable life insurance policies included in our Rabbi Trust. In 2010, there were market losses versus market gains in 2009.

POWER SUPPLY MATTERS

Power Supply Management Our power supply portfolio includes a mix of baseload and dispatchable resources. These resources serve our retail electric load requirements and any wholesale sale obligations into which we enter as part of a hedging strategy. We manage our power supply portfolio by attempting to optimize the economic value of these resources and to create a balance between our power supplies and load obligations.

Our power supply management philosophy is to strike a balance between cost and risk. We strive to minimize power costs while simultaneously keeping liquidity risks at conservative levels. Risk mitigation strategies are built around minimizing both forward price risks and operational risks while strictly limiting the potential for both our collateral exposure and inefficient deployment of capital. Other risks are mitigated by the power and transmission cost recovery process contained in the PCAM (see Retail Rates and Alternative Regulation). We also mitigate price risks through limited wholesale transactions that hedge market price risk, as discussed below. In addition, we purchased outage insurance, currently effective through early 2011, to help cover unexpected costs of major unplanned Vermont Yankee outages that could cause the plant to curtail deliveries under the current VY PPA. Financial Transmission Rights (FTRs) auctions provides us with opportunities to economically hedge our exposure to congestion charges that result from transmission system constraints between generator locations and where load is served. FTRs are awarded to successful bidders in periodic auctions that are administered by ISO-New England.

Our current power forecast suggests we have excess energy supply during 2011. We recently conducted a successful online auction to sell most of our excess energy in the forward market, on a unit-contingent basis, at fixed prices in order to reduce market price volatility and gain a measure of revenue certainty while remaining strictly within potential collateral exposure limits.

Attaining an investment-grade credit rating expanded the available collateral limits with our current counterparties and we have attracted additional counterparties that appear willing to transact with us. However, regardless of collateral limits and available counterparties, we expect to maintain our practice of constraining net transaction volumes with individual counterparties to mitigate potential collateral exposures during stressed market conditions.

Future Power Supply Long-term contracts with Vermont Yankee and Hydro-Québec provide the majority of our current power supply. There is some risk that future sources available to replace these contracts may be less reliable and impose significantly higher prices than current portfolio resources although supplies are more than adequate in the region and prices have moderated significantly since the peaks experienced in 2008. These contracts are described in more detail in Note 13 - Commitments and Contingencies.

Our contract for power purchases from VYNPC ends in March 2012, but there is a risk that we could lose this resource if the plant shuts down before that date. An early shutdown could cause our customers 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 forward market prices as of September 30, 2010, the incremental replacement cost of lost power is estimated to average $8.2 million annually over the remaining life of the contract. We are not able to predict whether there will be an early shutdown of the Vermont Yankee plant or whether the PSB would allow timely and full recovery of increased costs of such shutdown. An early shutdown, depending upon the specific circumstances, could involve cost recovery via the outage insurance described above and recoveries under the PCAM but, in general, would not be expected to materially impact financial results if the costs are recovered in retail rates in a timely fashion.

Entergy-Vermont Yankee has submitted a renewal application with the NRC and an application for a CPG with the PSB 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. Significant hurdles may prevent its relicensing. Potential operating, transparency and communication issues related to the plant have raised serious concerns among regulators and members of the Vermont Legislature, including some who have called for its temporary or permanent shutdown. An intervenor in the CPG case has requested that the PSB order a shutdown of the Vermont Yankee plant due to recent leaks at the site. The PSB has opened a new docket to consider that request.

On February 24, 2010, in a non-binding vote, the Vermont Senate voted against allowing the PSB to consider granting the Vermont Yankee plant another 20-year operating license after 2012. The new Vermont Legislature elected on November 2, 2010 could vote differently, although the political makeup of the House and Senate remains largely unchanged. Also, Vermont elected a new governor who advocated as a member of the Vermont Senate and during the gubernatorial campaign that the Vermont Yankee Plant should close when its current license expires. While circumstances could change and we expect to engage in a constructive dialogue with the new administration and legislature related to the continued operation of the Vermont Yankee Plant, we are unable to predict the outcome at this time.

At this time, Entergy-Vermont Yankee is attempting to overcome these concerns, and in April 2010, we began a new round of negotiations on a new contract. We rejected Entergy-Vermont Yankee's last public proposal, but both parties continue to exchange information and proposals. The parties are attempting to negotiate a purchased power contract in order that the state will have the value of such an agreement to consider should the other 20-year extension issues that have emerged be resolved. We cannot predict the outcome at this time.

Under the terms of sale of the plant in 2002, Entergy-Vermont Yankee also agreed to a Revenue Sharing Agreement ("RSA") for the period 2012 through 2022. The RSA will yield revenue to us on a certain MW portion of the plant's actual output whenever the average annual unit revenue exceeds a "strike price" that is established by formula beginning at $61/ MWh in 2012. Should the plant be relicensed and operate through March 2022, the effect of the RSA will be to provide a price cap-like effect (at the level of the strike price) on the net cost of a purchase of an equal quantity of power made at market prices. Protection from upward price volatility above the level of the RSA represents a significant economic value to our consumers.

Contract deliveries from our current Hydro-Québec contract will decline by approximately 19 percent after 2012, by approximately 84 percent after 2015 and will cease in 2016. The first reduction will serve to reduce the amount of the Company's power supply expected through October 2015. Hydro-Québec is engaged in the addition of approximately 4,000 MW of hydroelectric capacity in Quebec largely targeted for export partially via increased transmission capacity into the New England market.

New Hydro-Québec Agreement: On August 12, 2010 we, along with Green Mountain Power Corporation ("GMP"), Vermont Public Power Supply Authority ("VPPSA"), Vermont Electric Cooperative, Inc. ("VEC"), Vermont Marble Power Division of Omya Industries Inc. ("Vermont Marble"), Town of Stowe Electric Department ("Stowe"), City of Burlington, Vermont Electric Department ("BED"), Washington Electric Cooperative, Inc. ("WEC") and the 13 municipal members of VPPSA (collectively, the "Buyers") entered into an agreement for the purchase of shares of 218 MW to 225 MW of energy and environmental attributes from H.Q. Energy Services (U.S.) Inc. ("HQUS") commencing on November 1, 2012 and continuing through 2038.

The rights and obligations of the Buyers under this long-term power purchase and sale agreement with HQUS ("HQUS PPA"), including payment of the contract price and indemnification obligations, are several and not joint or joint and several. Therefore, we shall have no responsibility for the obligations, financial or otherwise, of any other party to the HQUS PPA. The parties have also entered into related agreements, including collateral agreements between each Buyer and HQUS, a Hydro-Québec guaranty, an allocation agreement among the Buyers, and an assignment and assumption agreement between us and Vermont Marble, related to the pending acquisition.

The HQUS PPA will replace approximately 65 percent of the existing VJO Power Contract discussed above, which along with the VY PPA supply the majority of Vermont's current power needs. The VJO Power Contract and the VY PPA expire within the next several years.

The obligations of HQUS and each Buyer are contingent upon the receipt of certain governmental approvals. On August 17, 2010, the Buyers filed a petition with the PSB asking for Certificates of Public Good under Section 248 of Title 30, Vermont Statutes Annotated. The PSB has established a schedule for the docket including technical hearings and final legal briefs in the first quarter of 2011. In the event the HQUS PPA is terminated with respect to any Buyer as a result of such Buyer's failure to receive governmental approvals, each of the other Buyers will have an option to purchase the additional energy.

Under the Agreement, subject to regulatory approval, we would be entitled to purchase an energy quantity of up to 85.4 MW from November 1, 2015 to October 31, 2016; 96.4 MW from November 1, 2016 to October 31, 2020; 98.4 MW from November 1, 2020 to October 31, 2030; 112.1 MW from November 1, 2030 to October 31, 2035; and 26.7 MW from November 1, 2035 to October 31, 2038.

Other Future Power Agreements: As we continue to build and diversify our power portfolio as planned and to comply with state law which establishes goals for renewable power in our mix, we have recently signed several agreements for clean and competitively priced renewable energy. On September 9, 2010, we agreed to purchase output from Iberdrola Renewables' planned Deerfield Wind Project. We will purchase 20 MW of the project's planned output for nine years.

Other recently signed agreements include: two separate agreements to purchase 30.3 percent of the actual output from Granite Reliable Wind project for 20 years beginning April 1, 2011 and an additional 20 percent for 15 years beginning in November 2012; an agreement to purchase the entire 4.99 MW output of Ampersand Gilman Hydro for five years starting April 1, 2012; and 15 MW of around-the-clock energy from J.P. Morgan Ventures Energy for the calendar years 2013 through 2015.

RECENT ENERGY POLICY INITIATIVES

In 2005, the state of Vermont created a renewable energy mandate under the Sustainably Priced Energy Development Program ("SPEED"). The primary SPEED goal is that, by January 1, 2012, Vermont utilities produce or purchase energy equal to 5 percent of the 2005 electricity sales, plus sales growth since then, from small-scale solar, wind, hydro and methane energy production ("SPEED resources").

An additional SPEED goal is that, by 2017, SPEED resources account for 20 percent of Vermont's electricity sales. The SPEED goal is a statewide target, rather than something specific to each utility. We believe we are on pace to achieve the 2012 SPEED targets.

In May, 2009, the Vermont Legislature amended the SPEED law to create a "Feed-In Tariff" (FIT) rate for SPEED resources smaller than 2.2 MW in capacity. FIT rates are available for a maximum of 50 MW of capacity. The incremental cost of electricity from FIT projects is to be borne proportionately by all Vermont utilities except Washington Electric Cooperative, which was exempted from the program.

In May 2010, the Vermont Legislature amended the SPEED law to allow existing farm methane generators (including our "Cow Power" generators) to qualify for the FIT. We supported this action.

The 2010 Legislature also repealed a Vermont law that precluded hydroelectric facilities with capacity above 80 MW from being considered as "renewable" resources. While there are no such facilities in Vermont, CVPS purchases power from Hydro-Québec, which does operate facilities larger than 80 MW. We anticipate no immediate impact from this change in policy.

RECENT ACCOUNTING PRONOUNCEMENTS AND TECHNICAL DEVELOPMENTS

Dodd-Frank Act On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Act") was signed into law. While the Act has broad implications to the financial services industry, there are some new mandates for public companies that may require changes in corporate governance, compensation, government regulation of the over-the-counter derivatives market, accounting and other areas. The regulations implementing the Act have not yet been drafted; however the SEC has begun issuing concept releases under certain provisions of the Act.

The Act requires entities to clear most over-the-counter derivatives through regulated central clearing organizations and to trade the derivatives on regulated exchanges. In September 2010, we filed for a waiver of the Dodd-Frank provision that ends the exemption under Section 2(h) of the Commodity Exchange Act ("CEA"). If granted, an extension of time will be provided, exempting us while regulatory rulemaking is taking place and while we evaluate whether our derivatives are subject to these regulations in the CEA or as adjusted in the Act. Even with this exemption, however, we may be subject to reporting requirements pursuant to an interim rule due out soon that will pertain to swap arrangements entered into before the Act. We are monitoring and evaluating the situation to ensure compliance with any such reporting requirements.

We are uncertain to what degree this legislation may affect our business in the future, but we are evaluating these additional regulatory requirements and the potential impact on our financial statements.

Also, see Part I, Item 1, Note 1 - Business Organization and Summary of Significant Accounting Policies to the accompanying Condensed Consolidated Financial Statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For the nine months ended September 30, 2010, there were no material changes from the disclosures included in Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2009 except as shown below.

Power-related derivatives We account for some of our power contracts as derivatives under FASB's guidance for derivatives and hedging. These derivatives are described in Management's Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Policies and Estimates. Summarized information related to the fair value of power contract derivatives is shown in the table below (dollars in thousands):

	Forward Energy Contracts	Financial Transmission Rights	Hydro-Quebec Sellback #3	Total
Total fair value at December 31, 2009	$269	$134	($149)	$254
Gains and losses (realized and unrealized)				
Included in earnings	2,376	32		2,408
Included in Regulatory and other assets/liabilities	2,367	20	149	2,536
Purchases, sales, issuances and net settlements	(2,376)	(133)		(2,509)
Total fair value at September 30, 2010	$2,636	$53	$0	$2,689
Estimated fair value at September 30, 2010 for changes in projected market price:				
10 percent increase	$1,935	$62	$0	$1,997
10 percent decrease	$3,336	$46	$0	$3,382

Pursuant to a PSB-approved Accounting Order, changes in fair value of all power-related derivatives are recorded as deferred charges or deferred credits on the Condensed Consolidated Balance Sheets depending on whether the change in fair value is an unrealized loss or unrealized gain, with an offsetting amount recorded as a decrease or increase in the related derivative asset or liability.

Equity Market Risk As of September 30, 2010, our pension trust held marketable equity securities of $56.7 million, our postretirement medical trust funds held marketable equity securities of $10.8 million, our Millstone Unit #3 decommissioning trust held marketable equity securities of $3.9 million and our Rabbi Trust held variable life insurance policies with underlying marketable equity securities of $2.4 million. These equity investments experienced positive performance through September 30, 2010 and positive performance in 2009. Also see Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources, and Note 11 - Pension and Postretirement Medical Benefits for additional information.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Management of the company, under the supervision and with participation of our Chief Executive Officer and Principal Financial and Accounting Officer, conducted an evaluation of the effectiveness of the design and operation of the company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934), as of September 30, 2010. Based on this evaluation, our Chief Executive Officer and Principal Financial and Accounting Officer concluded that, as of September 30, 2010, the company's disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting There were no changes in internal control over financial reporting that occurred during the quarter ended September 30, 2010 that have materially affected, or are reasonably likely to materially affect, the company's 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, results of operations or cash flows.

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, 2009, which could materially affect our business, financial condition or future results.

Item 6. Exhibits.

(a) List of Exhibits

10.1 Power Purchase and Sale Agreement between H.Q. Energy Services (U.S.), Inc. and Central Vermont Public Service Corporation, Green Mountain Power, Vermont Electric Cooperative, Inc., Vermont Public Power Supply Authority, Vermont Marble Power Division of Omya, Inc., City of Burlington, Vermont Electric Department, and The Town of Stowe Electric Department dated as of August 12, 2010 [portions of the exhibit were omitted pursuant to a request for confidential treatment on file with the SEC] (incorporated by reference to Exhibit 10.1 to the Company's Form 8-K filed with the SEC on August 18, 2010)

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
Sr. Vice President, Chief Financial Officer, and Treasurer

Dated November 8, 2010