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

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2008

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

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

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock $6 Par Value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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 Act). Yes ☐ No ☒

The aggregate market value of voting and non-voting common equity held by non affiliates of the registrant as of June 30, 2008 (2nd quarter) was approximately $150,729,379 (based on the $19.37 per share closing price of the Company's Common Stock, $6 Par Value, as reported on the New York Stock Exchange on June 30, 2008). In determining who are affiliates of the Company for purposes of computation, it is assumed that directors, officers, and other persons who held on December 31, 2008, more than 5 percent of the issued and outstanding Common Stock of the Company are "affiliates" of the Company. The characterization of such directors, officers, and other persons as affiliates is for the purposes of this computation only and should not be construed as a determination or admission for any other purpose.

On February 27, 2009 there were outstanding 11,610,905 shares of voting Common Stock, $6 Par Value.

DOCUMENTS INCORPORATED BY REFERENCE

The Company's Definitive Proxy Statement relating to its Annual Meeting of Stockholders to be held on May 5, 2009 to be filed with the Securities and Exchange Commission pursuant to Regulation 14A under the Securities Act of 1934, is incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
FORM 10-K - 2008
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Cautionary Statements Regarding Forward-Looking Information Statements contained in this report that are not historical fact are forward-looking statements within the meaning of the 'safe-harbor' provisions of the Private Securities Litigation Reform Act of 1995. Whenever used in this report, the words "estimate," "expect," "believe," or similar expressions are intended to identify such forward-looking statements. Forward-looking statements involve estimates, assumptions, risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Actual results will depend upon, among other things:

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

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

PART I

Item 1. Business

(a) General Description of Business Central Vermont Public Service Corporation ("we", "us", "our" 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 nearly two-thirds of the towns, villages and cities in Vermont. Our Vermont utility operation is our core business. We typically generate most of our revenues through retail electricity sales. We also sell excess power, if any, to third parties in New England and to ISO-New England, the operator of the region's bulk power system and wholesale electricity markets. The resale revenue generated from these sales helps to mitigate our power supply costs.

Our wholly owned subsidiaries include:

- Custom Investment Corporation ("Custom"), formed for the purpose of holding passive investments, including the stock of our subsidiaries that invest in regulated business opportunities. On October 13, 2003, we transferred our shares of Vermont Yankee Nuclear Power Corporation ("VYNPC") to Custom. The transfer to Custom does not affect our rights and obligations related to VYNPC.
- C.V. Realty, Inc., a real estate company that owns, buys, sells and leases real and personal property and interests therein related to the utility business.
- CVPSC - East Barnet Hydroelectric, Inc., formed for the purpose of financing and constructing a hydroelectric facility in Vermont, which became operational September 1, 1984. We have leased and operated it since the in-service date.
- Catamount Resources Corporation ("CRC"), formed for the purpose of holding our investments in unregulated business opportunities. CRC's wholly owned subsidiary, Eversant Corporation, engages in the sale and rental of electric water heaters in Vermont and New Hampshire through a wholly owned subsidiary, SmartEnergy Water Heating Services, Inc.

- In 2007, we dissolved our wholly owned subsidiary Connecticut Valley Electric Company, Inc. ("Connecticut Valley"), which had been incorporated under the laws of New Hampshire on December 9, 1948. Connecticut Valley distributed and sold electricity in parts of New Hampshire bordering the Connecticut River, until January 1, 2004, when it completed the sale of substantially all of its plant assets and its franchise to Public Service Company of New Hampshire. Its remaining assets were nominal.

Our equity ownership interests as of December 31, 2008 are summarized below:

- We own 58.85 percent of the common stock of VYNPC, which was initially formed by a group of New England utilities to build and operate a nuclear-powered generating plant in Vernon, Vermont. On July 31, 2002, the plant was sold to Entergy Nuclear Vermont Yankee, LLC ("Entergy-Vermont Yankee"). The sale agreement included a purchased power contract between VYNPC and Entergy-Vermont Yankee. Under the purchased power contract, VYNPC pays Entergy-Vermont Yankee for generation at fixed rates, and in turn, bills the purchased power contract charges from Entergy-Vermont Yankee with certain residual costs of service through a FERC tariff to us and the other Vermont Yankee sponsors. Although we own a majority of the shares of VYNPC, our ability to exercise control is effectively restricted by the purchased power contract, the sponsor agreement among the group of New England utilities that formed VYNPC and the composition of the board of directors under which it operates.
- We own 47.05 percent of the common stock and 48.03 percent of the preferred stock of Vermont Electric Power Company, Inc. ("VELCO"). In June 2006, VELCO transferred substantially all of its business operations and assets to Vermont Transco LLC ("Transco"). VELCO's wholly owned subsidiary, Vermont Electric Transmission Company, Inc., was formed to finance, construct and operate the Vermont portion of the 450 kV DC transmission line connecting the Province of Quebec with Vermont and the rest of New England.
- We own 33.02 percent of the voting equity units of Transco, which was formed by VELCO and its owners, including us, in June 2006. Transco owns and operates the high-voltage transmission system in Vermont. VELCO and its employees manage the operations of Transco under a Management Services Agreement. VELCO owns 14.14 percent of the voting equity units of Transco. Our total direct and indirect (through our VELCO ownership) interest in Transco is 39.67 percent of the voting equity units.
- We own 2 percent of the outstanding common stock of Maine Yankee Atomic Power Company ("Maine Yankee"), 2 percent of the outstanding common stock of Connecticut Yankee Atomic Power Company ("Connecticut Yankee") and 3.5 percent of the outstanding common stock of Yankee Atomic Electric Company ("Yankee Atomic"). All of the plants have been permanently shut down and have completed decommissioning.

We also own small generating facilities and have joint ownership interests in certain Vermont and regional generating facilities. These are described in Sources and Availability of Power Supply below.

(b) Financial Information about Industry Segments We have two principal operating segments, consisting of the principal regulated utility business and the aggregate of the other non-utility companies. See Part II, Item 8, Note 18 - Segment Reporting for financial information by segment.

(c) Narrative Description of Business As a regulated electric utility, we have an exclusive right to serve customers in our service territory, which can generally be expected to result in relatively stable revenue streams. The ability to increase our customer base is limited to acquisitions or growth within our service territory. Due to our geographic location and the nature of our customer base, weather and economic conditions are factors that can significantly affect retail sales revenue. Retail sales volume over the last 10 years has grown at an average rate of less than 1 percent per year, ranging from a decrease of over 2 percent in 2008 to increases of over 2 percent in other years.

Our operating revenues consist primarily of retail and resale sales. Retail sales are comprised of sales to a diversified customer mix, including residential, commercial and industrial customers. Sales to the five largest retail customers receiving electric service accounted for about 6 percent of our annual retail electric revenues for 2008, 2007 and 2006. Resale sales are comprised of long-term sales to third parties in New England, sales in the energy markets administered by ISO-New England and short-term system capacity sales. Operating revenues as of December 31 consisted of the following:

	Revenues			**Energy (mWh) Sales**		
	2008	2007	2006	**2008**	2007	2006
Retail Sales:						
Residential	**40%**	41%	38%	**33%**	33%	29%
Commercial	**32%**	33%	32%	**29%**	29%	27%
Industrial and other	**11%**	11%	12%	**13%**	14%	13%
Resale Sales	**14%**	12%	16%	**25%**	24%	31%
Other operating revenue	**3%**	3%	2%	**0%**	0%	0%

Retail Rates Our retail rates are set by the Vermont Public Service Board ("PSB") after considering the recommendations of Vermont's consumer advocate, the Vermont Department of Public Service ("DPS"). Fair regulatory treatment is fundamental to maintaining our financial stability. Rates must be set at levels to recover costs, including a market rate of return to equity and debt holders, in order to attract capital. The return on common equity of our regulated business did not exceed the allowed return for 2008, 2007 or 2006. See Part II, Item 8, Note 7 - Retail Rates and Alternative Regulation.

Wholesale Rates We provide wholesale transmission service to 10 network customers and six point-to-point customers under ISO-New England FERC Electric Tariff No. 3, Section II - Open Access Transmission Tariff (Schedules 21-CV and 20A-CV). We also provided wholesale transmission service to one network customer under a FERC rate schedule through October 18, 2008. We maintain an OASIS site for transmission on the ISO-New England web page.

Sources and Availability of Power Supply Our power supply portfolio includes sources used to serve our retail electric load requirements plus any wholesale obligations into which we enter. Our current power forecast shows energy purchase and production amounts in excess of load obligations through 2011. For the year ended December 31, 2008 energy generation and purchased power required to serve retail and firm wholesale customers totaled 2,406,575 mWh. The maximum one-hour integrated demand during that period was 414.4 MW and occurred on January 3, 2008. For 2007, our energy generation and purchased power required to serve retail and firm wholesale customers totaled 2,487,279 mWh. The maximum one-hour integrated demand was 420.6 MW and occurred on August 6, 2007. The sources of energy and capacity available to us for the year ended December 31, 2008 are as follows:

	Net Effective Capability 12 Month Average MW	Generated and Purchased mWh	Percent
Wholly Owned Plants:			
Hydro	42.8	231,193	7.3
Diesel and Gas Turbine	24.7	625	0.0
Jointly Owned Plants:			
Millstone #3	19.8	152,782	4.8
Wyman #4	10.8	2,276	0.1
McNeil	10.7	50,440	1.6
Long-Term Purchases:			
VYNPC	179.5	1,417,144	44.8
Hydro-Quebec	143.2	937,923	29.7
Independent Power Producers	34.6	202,193	6.4
Other Purchases:			
System and other purchases	0.4	93,918	3.0
NEPOOL (ISO-New England)	-	71,444	2.3
Total	466.5	3,159,938	100.0

Wholly Owned Plants: Our wholly owned plants are located in Vermont, and have a combined nameplate capacity of 74.2 MW. We operate all of these plants, which include: 1) 20 hydroelectric generating facilities with nameplate capacities ranging from a low of 0.3 MW to a high of 7.5 MW, for an aggregate nameplate capacity of 45.3 MW; 2) two oil-fired gas turbines with a combined nameplate capacity of 26.5 MW; and 3) one diesel peaking unit with a nameplate capacity of 2.4 MW. The diesel plant has been deactivated since 2007 but its capacity is included in the above totals.

Jointly Owned Plants: We have joint-ownership interests in three generating facilities and one transmission facility. As shown in the sources and availability of power supply table above, we receive our share of output and capacity from the three generating facilities. The Highgate Converter is directly connected to the Hydro-Quebec system to the north and to the Transco system for delivery of power to Vermont utilities. This facility can deliver power in either direction, but predominantly delivers power from Hydro-Quebec to Vermont. Additional information about these facilities is shown in the table below.

	Fuel Type	**Ownership**	**Date In Service**	**MW Entitlement**
Wyman #4	Oil	1.78%	1978	10.8
Joseph C. McNeil	Various	20.00%	1984	10.8
Millstone Unit #3	Nuclear	1.73%	1986	20.0
Highgate Transmission Facility		47.52%	1985	N/A

VYNPC: We purchase our entitlement share of Vermont Yankee plant output from VYNPC under a long-term power contract between VYNPC and Entergy-Vermont Yankee. The contract extends through the plant's current license life, which expires in March 2012. Prices under the contract range from $42 to $45 per mWh, and the contract contains a provision known as the "low market adjuster" that calls for a downward adjustment in the contract price if market prices for electricity fall by defined amounts. If market prices rise, the contract prices are not adjusted upward in excess of the contract price.

Entergy-Vermont Yankee has no obligation to supply energy to VYNPC over the amount the plant is producing, so we receive reduced amounts when the plant is operating at a reduced level, and no energy when the plant is not operating. We are responsible for purchasing replacement energy at these times. The next refueling outage is scheduled for mid-2010. We typically enter into forward purchase contracts for replacement power during scheduled outages. We also have forced outage insurance in place to cover additional costs, if any, of obtaining replacement power from other sources if the Vermont Yankee plant experiences unplanned outages through March 31, 2009. We are currently working with an insurance broker to obtain insurance coverage for the remainder of 2009 through March of 2012 when the contract between Entergy-Vermont Yankee and VYNPC ends. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Power Supply Matters.

Entergy-Vermont Yankee has submitted a renewal application with the federal Nuclear Regulatory Commission ("NRC") for a 20-year extension of the Vermont Yankee plant operating license. Entergy-Vermont Yankee also needs PSB and Vermont Legislature approval to continue to operate the plant beyond 2012. At this time, Entergy-Vermont Yankee has not received approvals for the license extension, but we are continuing to participate in negotiations for a power contract beyond 2012 and cannot predict the outcome at this time. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Other Business Risks - Power Supply Risks.

Hydro-Quebec: We purchase power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract. The VJO is a group of Vermont electric companies, municipal utilities and cooperatives, of which we are a member. The VJO Power Contract has been in place since 1987 and purchases under the contract began in 1990. Related contracts were subsequently negotiated between us and Hydro-Quebec that altered 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. As of November 1, 2007 the annual load factor was reduced from 80 percent to 75 percent, and it will remain at 75 percent until the contract ends, unless the contract is changed or there is a reduction due to adverse hydraulic conditions.

Independent Power Producers: We purchase power from several Independent Power Producers ("IPPs") who own qualifying facilities under the Public Utilities Regulatory Policies Act of 1978. These facilities use water and biomass as fuel. Most of the power is allocated by a state-appointed purchasing agent that assigns power to all Vermont utilities under PSB rules.

System and Other Purchases, including ISO-New England: We participate in the New England regional wholesale electric power markets operated by ISO-New England, Inc., the regional bulk power transmission organization established to assure reliable and economical power supply in New England, which is governed by the Federal Energy Regulatory Commission ("FERC"). We also engage in short-term purchases with other third parties, primarily in New England, to minimize net power costs and power supply risks to our customers. We enter into forward purchase contracts when additional supply is needed and enter into forward sale contracts when we forecast excess supply. On an hourly basis, power is sold or bought through ISO-New England's settlement process to balance our resource output and load requirements.

See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Power Supply Matters and Part II, Item 8, Note 17 - Commitments and Contingencies for additional information related to our power supply and related long-term power contracts.

Franchise Pursuant to Vermont statute (30 V.S.A. Section 249), the PSB has established the service area in which we currently operate. Under 30 V.S.A. Section 251(b) no other company is legally entitled to serve any retail customers in our established service area except as described below.

An amendment to Title 30 V.S.A. Section 212(a) enacted May 28, 1987 authorizes the DPS to purchase and distribute power at retail to all consumers of electricity in Vermont, subject to certain preconditions specified in sections 212(b) and 212(c). Section 212(b) provides that a review board, consisting of the governor and certain other designated legislative officers, review and approve any retail proposal by the DPS if the review board is satisfied that the benefits outweigh any potential risk to the state. However, the DPS may proceed to file the retail proposal with the PSB either upon approval by the review board or failure of the review board to act within 60 days of the submission. Section 212(c) provides that the DPS shall not enter into any retail sales arrangement before the PSB determines that it is appropriate. The PSB assesses the following factors in reaching its conclusion: 1) the need for the sale; 2) the rates are just and reasonable; 3) the sale will result in economic benefit; 4) the sale will not adversely affect system stability and reliability; and 5) the sale will be in the best interest of ratepayers.

Section 212(d) provides that upon PSB approval of a DPS retail sales request, Vermont utilities shall make arrangements for distributing such electricity on terms and conditions that are negotiated. Failing such negotiation, the PSB is directed to determine such terms as will compensate the utility for all costs reasonably and necessarily incurred to provide such arrangements. Such sales have not been made in our service area since 1993.

In addition, Chapter 79 of Title 30 of the V.S.A. authorizes municipalities to acquire the electric distribution facilities located within their boundaries. In Vermont, the exercise of such authority is conditioned upon an affirmative three-fifths vote of the legal voters in an election and upon the payment of just compensation, including severance damages. Just compensation may be determined either by negotiation between the municipality and the utility or, in the event the parties fail to reach an agreement, by the PSB after a hearing. If either party is dissatisfied, the statute allows an appeal of the PSB's determination to the Vermont Supreme Court.

Over the years a handful of municipalities have investigated the possibility of acquiring our distribution facilities. However, no municipality served by us has successfully established a municipal electric distribution system. We cannot predict whether efforts to municipalize portions of our service territory will occur in the future or be successful, and if so, what the impact would be on our financial condition.

Regulation We are subject to regulation by the PSB, other state commissions, FERC and the NRC as described below.

State Commissions: As described above we are subject to the regulatory authority of the PSB with respect to rates and terms of service. Along with VELCO and Transco, we are subject to PSB jurisdiction related to securities issuances, planning and construction of generation and transmission facilities and various other matters. Additionally, the Maine Public Utilities Commission exercises limited jurisdiction over us based on our joint-ownership interest as a tenant-in-common of Wyman #4, and the Connecticut Department of Public Utility Control has similar limited jurisdiction based on our interest in Millstone Unit #3.

Federal Power Act: Certain phases of our business and that of VELCO and Transco, including certain rates, are subject to regulation by the FERC. We are a licensee of hydroelectric developments under Part I of the Federal Power Act and along with Transco, we are interstate public utilities under Parts II and III, as amended and supplemented by the National Energy Act. On February 25, 2009, we received a federal license to continue to operate our Carver Falls hydroelectric facility and on February 26, 2009, we received a federal license to continue to operate our Silver Lake hydroelectric facility. These projects represent about 4.1 MW, or 9 percent of our hydroelectric nameplate capacity.

Federal Energy Policy Act of 2005: The Federal Energy Policy Act of 2005 ("EPACT") includes numerous provisions meant to increase domestic gas and oil supplies, improve energy system reliability, build new nuclear power plants, and expand renewable energy sources. It also repealed the Public Utility Holding Company Act of 1935, effective February 2006. By reason of our ownership of utility subsidiaries, we are a holding company, as defined in EPACT. We have received a blanket exemption from the FERC to acquire securities of Transco, which previously required FERC approval.

NRC: The nuclear generating facilities in which we have an interest are subject to extensive regulation by the NRC. The NRC is empowered to regulate siting, construction and operation of nuclear reactors with respect to public health, safety, environmental and antitrust matters. Under its continuing jurisdiction, the NRC may require modification of units for which operating licenses have already been issued, or impose new conditions on such licenses, or require that the operation of a unit cease or that the level of operation of a unit be temporarily or permanently reduced.

Environmental Matters We are subject to environmental regulations in the licensing and operation of the generation, transmission, and distribution facilities in which we have an interest, as well as the licensing and operation of the facilities in which we are a co-licensee. These environmental regulations are administered by local, state and federal regulatory authorities and may impact our generation, transmission, distribution, transportation and waste-handling facilities with respect to air, water, land and aesthetic qualities.

We cannot presently forecast the costs or other effects that environmental regulation may ultimately have on our existing and proposed facilities and operations. We believe that any such prudently incurred costs related to our utility operations would be recoverable through the ratemaking process. See Part II, Item 8, Note 17 - Commitments and Contingencies.

Competitive Conditions Competition currently takes several forms. At the wholesale level, New England has implemented its version of FERC's "standard market design" ("SMD"), which is a detailed competitive market framework that has resulted in bid-based competition of power suppliers rather than prices set under cost-of-service regulation. Similar versions of SMD have been implemented in New York and a large abutting multi-state region referred to as PJM. At the retail level, customers have long had energy options.

Competition in the energy services market exists between electricity and fossil fuels. In the residential and small commercial sectors, this competition is primarily for electric space and water heating from propane and oil dealers. Competitive issues are price, service, convenience, cleanliness, automatic delivery and safety.

In the large commercial and industrial sectors, cogeneration and self-generation are the major competitive threats to network electric sales. Competitive risks in these market segments are primarily related to seasonal, one-shift milling operations that can tolerate periodic power outages common to such forms of cogeneration or self-generation, and for industrial or institutional customers with steady heat loads where the generator's waste heat can be used in their manufacturing or space conditioning processes. Competitive advantages for electricity in those segments are: cost stability; convenience; cost of back-up power sources or alternatively, reliability; space requirements; noise problems; air emission and site permit issues; and maintenance requirements. However, there may be some circumstances where distributed generation, net metering and cogeneration could provide benefits to us in the constrained areas of our system.

Another possible competitive threat we face is the potential for customers to acquire our assets through a process known as municipalization. This is described above under the caption Franchise.

Seasonal Nature of Business Our kilowatt-hour sales and revenues are typically higher in the winter and summer than in the spring and fall, as sales tend to vary with weather. Ski area and other winter-related recreational activities along with associated lodging, longer hours of darkness and heating loads from cold weather contribute to higher sales in the winter, while air conditioning generates higher sales in the summer. Consumption is least in the spring and fall, when there is decreased heating or cooling load.

Capital Expenditures Our business is capital-intensive and requires annual construction expenditures to maintain the distribution system. Capital expenditures for the next five years are expected to range from $32 million to $62 million annually, including an estimated total of $42 million over the 5-year period for our advanced meter infrastructure and "smart grid" network, which we call CVPS SmartPower™. These are subject to continuing review and adjustment and actual capital expenditures and timing may vary. Competitive advantages may also develop for us as we begin to implement CVPS SmartPower™, within our service territory. A smart grid delivers electricity from suppliers to consumers using digital technology to save energy and cost. Although there are specific and proven smart grid technologies in use, *smart grid* is an aggregate term for a set of related technologies rather than a name for a specific technology with a generally agreed-upon specification. Some of the expected benefits of such a modernized electricity network include reducing consumer power consumption during peak hours, enabling grid connection of distributed generation power, and incorporating grid energy storage for distributed generation load balancing.

Number of Employees Local Union No. 300, affiliated with the International Brotherhood of Electrical Workers ("IBEW"), represents our operating and maintenance employees. At December 31, 2008, we had 549 employees, of which 218 are represented by the union. On December 31, 2008, we agreed with our employees represented by the union, to a new five-year contract, which expires on December 31, 2013.

Executive Officers of Registrant
The following sets forth the executive officers. There are no family relationships among the executive officers. The term of each officer is for one year or until a successor is elected. Officers are normally elected annually.

Name and Age	**Office**	**Officer Since**
Robert H. Young, 61	President and chief executive officer	1987
Pamela J. Keefe, 43	Vice president, chief financial officer, and treasurer	2006
William J. Deehan, 56	Vice president - power planning and regulatory affairs	1991
Joan F. Gamble, 51	Vice president - strategic change and business services	1998
Brian P. Keefe, 51	Vice president - government and public affairs	2006
Joseph M. Kraus, 53	Senior vice president - operations, engineering and customer service	1987
Dale A. Rocheleau, 50	Senior vice president, general counsel and corporate secretary	2003

Mr. Young joined the Company in 1987 and was elected to his present position in 1995. Mr. Young also serves as president, CEO, and chair of the following CVPS subsidiaries: CVPSC - East Barnet Hydroelectric, Inc.; CV Realty, Inc.; Custom Investment Corporation; Catamount Resources Corporation; Eversant Corporation; and SmartEnergy Water Heating Services, Inc. He serves as chair of the board of Directors of CVPS affiliate: Vermont Yankee Nuclear Power Corporation. He is also director of the following CVPS affiliates: Vermont Electric Power Company, Inc., and Vermont Electric Transmission Company, Inc. Mr. Young is director of the Edison Electric Institute, Inc., Chittenden Trust Company, Vermont Business Roundtable, Associated Industries of Vermont, and the Weston Playhouse Theatre Company.

Ms. Keefe joined the company in June 2006. Prior to joining the company, from 2003 to 2006, she served as senior director of financial strategy and assistant treasurer of IDX Systems Corporation ("IDX"); from 1999 to 2003 she served as director of financial planning and analysis and assistant treasurer at IDX. Ms. Keefe serves as director, vice president, chief financial officer, and treasurer of our subsidiaries: CVPSC - East Barnet Hydroelectric, Inc.; C.V. Realty, Inc.; Custom; CRC; Eversant Corporation; and, SmartEnergy Water Heating Services, Inc. She also serves as a director of our affiliate, VYNPC.

Mr. Deehan joined the company in 1985 with nine years of utility regulation and related research experience. Mr. Deehan was elected to his present position in May 2001. He is a director of the Rutland County Boys and Girls Club.

Ms. Gamble joined the company in 1989 with 10 years of electric utility and related consulting experience. Ms. Gamble was elected to her present position in August 2001. Ms. Gamble also serves as vice president - strategic change and business services for our subsidiary, Eversant Corporation. She serves as a director for our subsidiaries, Eversant Corporation and SmartEnergy Water Heating Services, Inc. She is also on the board of the Vermont Achievement Center, Rutland Regional Medical Center, Rutland Regional Health Service, and Vermont Public Television.

Mr. Keefe joined the company in December 2006. Prior to being elected to his present position he served as vice president for governmental affairs from December 2006 to September 2007. Prior to joining the company, from 2000 to 2006, he served as a senior aide to U.S. Senator James M. Jeffords, focusing on energy, environment and economic development issues, and serving as liaison between Vermont constituents and Washington, D.C. policymakers. He is on the board of the Vermont Chamber of Commerce and a member of the Vermont Council on the Future of Vermont.

Mr. Kraus joined the company in 1981. Prior to being elected to his present position he served as senior vice president engineering and operations, general counsel, and secretary from May 2003 until November 2003. Mr. Kraus serves as director of our subsidiaries: CVPSC - East Barnet Hydroelectric, Inc.; C.V. Realty, Inc.; Custom; CRC; Eversant Corporation; and, SmartEnergy Water Heating Services, Inc.

Mr. Rocheleau joined the company in November 2003. Prior to being elected to his present position he served as senior vice president for legal and public affairs, and corporate secretary from November 2003 to September 2007. Prior to joining the company, he served as director and attorney at law from 1992 to 2003 with Downs Rachlin Martin, PLLC. Mr. Rocheleau serves as director, senior vice president, general counsel and corporate secretary of our subsidiaries: CVPSC - East Barnet Hydroelectric, Inc.; C.V. Realty, Inc.; Custom; CRC; Eversant Corporation; and SmartEnergy Water Heating Services, Inc.

Energy Conservation and Load Management The primary purpose of Conservation and Load Management programs is to offset need for long-term power supply and delivery resources that are more expensive to purchase or develop than customer-efficiency programs, including unpriced external factors such as emissions and economic risk. The Vermont Energy Efficiency Utility (“EEU”), created by the state of Vermont to implement energy efficiency programs throughout Vermont, began operation in January 2000. We have a continuing obligation to provide customer information and referrals, and coordination of customer service, power quality, and any other distribution utility functions, which may intersect with the EEU’s activities.

We have retained the obligation to provide demand side management programs targeted at deferral of our transmission and distribution projects, as identified in Vermont’s Distributed Utility Planning (“DUP”). DUP is designed to ensure that safe, reliable delivery services are provided at least cost. The PSB recently approved a similar process for the bulk transmission lines owned and operated by Transco. The PSB appointed three members of the public, along with representatives of the state’s utilities, including us, to the newly created Vermont State Planning Committee to oversee that process. In 2006, the Vermont Legislature also gave Efficiency Vermont authority to target the delivery of energy efficiency to specific geographic areas to defer transmission and distribution upgrades. This process began for the first time in 2007.

Recent Energy Policy Initiatives Several laws have been passed since 2005 that impact electric utilities in Vermont. While provisions of recently passed laws are now being implemented, there is continued interest in additional policies designed to reduce electricity consumption, promote renewable energy and reduce greenhouse gas emissions. We continue to monitor regional and federal proposals that may have an impact on our operations. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Recent Energy Policy Initiatives.

(d) Financial Information about Geographic Areas Neither we nor our subsidiaries have any foreign operations or export sales. The regulated utility business engages in the purchase, production, transmission, distribution and sale of electricity in Vermont. SmartEnergy Water Heating Services, Inc. engages in the sale and rental of electric water heaters in Vermont and New Hampshire.

(e) Available Information
We make available free of charge through our Internet Web site, *www.cvps.com*, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after electronically filing with the Securities and Exchange Commission ("SEC"). Access to the reports is available from the main page of the Internet Web site through "Investor Relations." Our Corporate Ethics and Conflict of Interest Policy, Corporate Governance Guidelines, and Charters of the Audit, Compensation and Corporate Governance Committees are also available on the Internet Web site. Access to these documents is available from the main page of our Internet Web site under "About us" and then "Corporate Governance." Printed copies of these documents are also available upon written request to the Assistant Corporate Secretary at our principal executive offices. Our reports, proxy, information statements and other information are also available by accessing the SEC's Internet Web site, *www.sec.gov*, or at the SEC's Public Reference Room at 100 F Street N.E., Washington, D.C. 20549. Information regarding operation of the Public Reference Room is available by calling the SEC at 1-800-732-0330.

Item 1A. Risk Factors
We operate in a market and regulatory environment that involves significant risks, many of which are beyond our control, cannot be limited cost-effectively or may occur despite our risk-mitigation strategies. Each of the following risks could have a material effect on our performance. Also see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Other Business Risks and Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk.

Our business is affected by local, national and worldwide economic conditions, and due to current market volatility, we have a number of cash flow risks. If the current economic crisis intensifies or is sustained for a protracted period of time, potential disruptions in the capital and credit markets may adversely affect our business. There could be adverse effects on: the availability and cost of short-term funds for liquidity requirements; the availability of financially stable counterparties for forward purchase and forward sale of power; the availability and cost of long-term capital to fund our asset management plan and future investments in Transco; additional funding requirements for our pension trust due to declines in asset values to fund pension liabilities; and the performance of the assets in our Rabbi Trust and decommissioning trust funds.

Longer-term disruptions in the capital markets as a result of economic uncertainty, changes in regulation, reduced financing alternatives, or failures of financial institutions could adversely affect our access to the funds needed to operate our business. Such prolonged disruptions could require us to take measures to conserve cash until the markets stabilize. In addition, if our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition could be harmed, and future results of operations could be adversely affected.

The global economic crisis has resulted in a significant decline in lending activity. We have a $40 million unsecured revolving credit facility with a bank. Our access to funds under the revolving credit facility is dependent on the ability of the counterparty bank to meet the funding commitments. The counterparty bank may not be able to meet the funding commitments if it experiences shortages of capital and liquidity or excessive volumes of borrowing requests from other borrowers within a short period of time.

Continued turbulence in the U.S. capital markets could limit or delay our ability to obtain additional outside capital on reasonable terms, and could negatively affect our ability to remarket and keep outstanding $10.8 million of our revenue bonds with monthly interest rate resets.

We have other business risks related to liquidity. An extended unplanned Vermont Yankee plant outage or similar event could have a significant effect on 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.

Any disruption could require us to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures and reducing dividend payments or other discretionary uses of cash.

We currently have a $40 million credit facility to provide liquidity for general corporate purposes, including working capital needs and power contract performance assurance requirements in the form of funds borrowed and letters of credit. We also raised $20.9 million, net of issuance costs, in a secondary offering of our common stock in November, 2008. The proceeds will be used for general corporate purposes including investments in our core infrastructure to maintain system reliability. If we are ever unable to secure needed funding, we would need to review our corporate goals in response to the financial limitation. 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 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 described above, as a result of high power market prices.

A related liquidity risk is our growing reliance on cash distributions from one of our affiliates. Transco's ability to pay distributions is subject to its financial condition and financial covenants in the various loan documents to which it is a party. Although it is a regulated business, Transco may not always have the resources needed to pay distributions with respect to the ownership units in the same manner as VELCO paid in the past.

Likewise, our business follows the economic cycles of the customers we serve. The economic downturn and increased cost of energy supply could adversely affect energy consumption and therefore impact our results of operations. Economic downturns or periods of high energy supply costs typically lead to reductions in energy consumption and increased conservation measures. These conditions could adversely impact the level of energy sales and result in less demand for energy delivery. However, the effect of unanticipated reduced consumer demand on our revenue will be offset to a large degree by the power cost and earnings sharing adjustment mechanism in the alternative regulation plan effective January 1, 2009. Anticipated consumer demand is reflected in base rates set annually under the plan.

Economic conditions in our service territory also impact our collections of accounts receivable and financial results.

An inability to access capital markets at attractive rates could materially increase our expenses. We rely on access to capital markets as a significant source of liquidity for capital requirements not satisfied by operating cash flows. Our business is capital intensive and dependent on our ability to access capital at rates and on terms we determine to be attractive. If our ability to access capital becomes significantly constrained, our interest costs could increase materially, our financial condition could be harmed and future results of operations could be adversely affected.

Our current credit rating is below investment grade. In June 2005, Standard & Poor's Ratings Services lowered our corporate credit rating to BB+, which is below investment grade. We believe that restoration of our credit rating is critical to our long-term success. While our corporate credit rating remains below investment grade the cost of capital, which is ultimately passed on to our customers, could be greater than it otherwise would be. That, combined with collateral requirements from creditors and for power purchases and sales, makes restoration of our credit rating critical. Looking ahead, as long-term power contracts with Hydro-Quebec and Vermont Yankee begin to expire three years from now, these ratings become even more important. Access to needed capital is also more of a concern as a non-investment-grade company, particularly in the current U.S. credit environment.

We are subject to substantial regulation on the federal, state and local levels, and changes in regulatory or legislative policy could jeopardize our full recovery of costs. At the federal level, the FERC regulates our transmission rates, affiliate transactions, the acquisition by us of securities of regulated entities and certain other aspects of our business. The PSB regulates the rates, terms and conditions of service, various business practices and transactions, financings, transactions between us and our affiliates, and the siting of our transmission and generation facilities and our ability to make repairs to such facilities. Our allowed rates of return, rate structures, operation and construction of facilities, rates of depreciation and amortization, and recovery of costs (including decommissioning costs and exogenous costs such as storm response-related expenses), are all determined within the regulatory process. The timing and adequacy of regulatory relief directly affect our results of operations and cash flows. Under state law, we are entitled to charge rates that are sufficient to allow us an opportunity to recover reasonable operation and capital costs and a return on investment to attract needed capital and maintain our financial integrity, while also protecting relevant public interests. We prepare and submit periodic filings with the DPS for review and with the PSB for review and approval. The PSB may deny the recovery of costs incurred for the operation, maintenance, and construction of our regulated assets, as well as reduce our return on investment. Furthermore, compliance with regulatory and legislative requirements could result in substantial costs in our operations that may not be recovered.

We have risks related to our power supply and wholesale power market prices. Our material power supply contracts are with Hydro-Quebec and VYNPC. The power supply contracts with Vermont Yankee and Hydro-Quebec comprise the majority of our total annual energy purchases. Combined, these contracts amounted to approximately 70 to 80 percent of our total energy purchases in 2008. If one or both of these sources become unavailable for a period of time, there could be exposure to high wholesale power prices and that amount could be material. Additionally, this could significantly impact liquidity due to the potentially high cost of replacement power and performance assurance collateral requirements arising from purchases through ISO-New England or third parties. Most incremental replacement power costs would be recovered through our power cost adjustment mechanism in the alternative regulation plan, which is effective on January 1, 2009, or we could seek emergency rate relief from our regulators if this were to occur. Such relief may or may not be provided and if it is provided we cannot predict its timing or adequacy.

Our contract for power purchases from Vermont Yankee 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. Deliveries under the contract with Hydro-Quebec end in 2016, but the level of deliveries will begin to decrease after 2012. 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.

We are subject to investment price risk due to equity market fluctuations and interest rate changes. Interest rate changes and volatility in the equity markets could impact the values of the debt and equity securities in our pension and postretirement medical trust funds and the valuation of pension and other benefit liabilities, affecting pension and other benefit expenses, contributions to the external trust funds and our ability to meet future pension and postretirement benefit obligations. Interest rate changes and volatility in the equity markets could also impact the value of the debt securities in our nuclear decommissioning trust.

Active employee and retiree healthcare and pension costs are a significant part of our cost structure. The costs associated with healthcare or pension obligations could escalate at rates higher than anticipated, which could adversely affect our results of operations and cash flows. Also, see Part II, Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Policies and Estimates, Pension and Postretirement Medical Benefits.

The demand for our services and our ability to provide them without material unplanned expenses are directly affected by weather conditions. We serve a largely rural, rugged service territory with dense forestation that is subject to extreme weather conditions. Storm activity has been significant in recent years, with the two most expensive storms in our history occurring in 2007 and 2008. Our results of operations can be affected by changes in weather. Severe weather conditions such as ice and snow storms, high winds and natural disasters may cause outages and property damage that may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned under these conditions would be particularly burdensome during a peak demand period. We typically receive the five-year average of storm restoration costs in our rates, but unexpected storms or extraordinarily severe weather can dramatically increase costs, with a significant lapse of time before we recover these costs through our rates. Weather conditions also directly influence the demand for electricity.

The loss of key personnel or the inability to hire and retain qualified employees could have an adverse effect on our business, financial condition and results of operations. Our operations depend on the continued efforts of our employees. Retaining key employees and maintaining the ability to attract new employees are important to both our operational and financial performance. A significant portion of our workforce, including many workers with specialized skills maintaining and servicing the electrical infrastructure, will be eligible to retire over the next five to 10 years. Also, members of our management or key employees may leave the company unexpectedly. Such highly skilled individuals and institutional knowledge cannot be quickly replaced due to the technically complex work they perform.

Anti-takeover provisions of Vermont law, our articles of association and our bylaws may prevent or delay an acquisition of us that stockholders may consider favorable or attempts to replace or remove our management that could be beneficial to our stockholders. Our articles of association and bylaws contain provisions that could make it more difficult for a third party to acquire us without the consent of our board of directors. They provide for our board of directors to be divided into three classes serving staggered terms of three years and permit removal of directors only for cause by the holders of not less than 80 percent of the shares entitled to vote (except where our Senior Preferred Stock has a right to participate in voting after certain arrearages in payments of dividends). Additionally, they require advance notice of stockholder proposals and stockholder nominations to the board of directors. In addition, they impose restrictions on the persons who may call special stockholder meetings. In addition, Vermont law allows directors to consider the interests of constituencies other than stockholders in determining appropriate board action on a recommendation of a business combination to stockholders. The approval of a U.S. government regulator or the PSB will also be required of certain types of business combination transactions. These provisions may delay or prevent a change of control of our company even if this change of control would benefit our stockholders.

Our ability to provide energy delivery and commodity services depends on our operations and facilities and those of third parties, including ISO-New England and electric generators from whom we purchase electricity. The loss of use or destruction of our facilities or the facilities of third parties that are used in providing our services, or with which our electric facilities are interconnected, due to extreme weather conditions, breakdowns, war, acts of terrorism or other occurrences could greatly reduce potential earnings and cash flows and increase our costs of repairs and/or replacement of assets. While we carry property insurance to protect certain assets and general regulatory precedent may provide for the recovery of losses for such incidents, our losses may not be fully recoverable through insurance or customer rates.

We use derivative instruments, such as forward contracts, to manage our commodity risk. We could recognize financial losses as a result of volatility in the market values of these contracts. We also bear the risk of a counterparty failing to perform. While we employ prudent credit policies and obtain collateral where appropriate, counterparty credit exposure cannot be eliminated, particularly in volatile energy markets.

Our ability to hedge our commodity market risk depends on our ability to accurately forecast supply and demand in future periods. Because of changes in weather, customer demand and availability of sources from period to period, we may hedge amounts that are greater or less than our actual commodity deliveries. Gains or losses on ineffective hedges are marked to market, but we have received approval for regulatory accounting treatment of these mark-to-market adjustments, so there is no impact on our income statement.

We are subject to extensive federal, state and local environmental regulation. We are subject to federal, state and local environmental regulations that monitor, among other things, emission allowances, pollution controls, maintenance, site remediation, equipment upgrades and management of hazardous waste. Various governmental agencies require us to obtain environmental licenses, permits, inspections and approvals. Compliance with environmental laws and requirements can impose significant costs, reduce cash flows and result in plant shutdowns or reduced plant output and could have a material adverse effect on our financial position, results of operations or cash flows.

In addition, global climate change issues have received an increased focus on the federal and state government levels which could potentially lead to additional rules and regulations that impact how we operate our business, including power plants we own and general utility operations. The ultimate impact on our business would be dependent upon the specific rules and regulations adopted and cannot be determined at this time.

Any failure by us to comply with environmental laws and regulations, even if due to factors beyond our control or reinterpretations of existing requirements, could also increase costs. Existing environmental laws and regulations may be revised or new laws and regulations seeking to protect the environment may be adopted or become applicable to us. The cost impact of any such legislation would be dependent upon the specific requirements adopted and cannot be determined at this time. Also, see Part II, Item 7 - Recent Energy Policy Initiatives.

Adoption of new accounting pronouncements and application of SFAS No. 71 can impact our financial results. The adoption of new accounting standards and changes to current accounting policies or interpretations of such standards may materially affect our financial position, results of operations or cash flows. Accounting policies also include industry-specific accounting standards applicable to rate-regulated utilities (SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, or SFAS No. 71). If we determine that we no longer meet the criteria under SFAS No. 71, the accounting impact would be an extraordinary charge to operations of $8.9 million on a pre-tax basis as of December 31, 2008, assuming no stranded cost recovery would be allowed through a rate mechanism. We would also be required to record pension and postretirement costs of $46 million on a pre-tax basis to Accumulated Other Comprehensive Loss and $0.9 million to Retained Earnings as a reduction in stockholders' equity and would be required to determine any potential impairment to the carrying costs of deregulated plant. The financial statement impact resulting from discontinuance of SFAS No. 71 might also trigger certain defaults under our current financial covenants.

The effect of the adverse impacts from these risk factors on our utility earnings could be mitigated by the earnings sharing adjustment mechanism in the alternative regulation plan effective January 1, 2009.

Item 1B. Unresolved Staff Comments

None

Item 2. Properties

We hold in fee all of our principal plants and important units, including those of our consolidated subsidiaries. Transmission and distribution facilities that are not located in or over public highways are, with minor exceptions, located on land owned in fee or pursuant to easements, most of which are perpetual. Transmission and distribution lines located in or over public highways are located pursuant to authority conferred on public utilities by statute, subject to regulation of state or municipal authorities. Substantially all of our utility property and plant is subject to liens under our First Mortgage Indenture.

Our properties are operated as a single system that is interconnected by the transmission lines of Transco, New England Power and Public Service Company of New Hampshire. We own and operate 23 small generating stations in Vermont with a total current nameplate capability of 74.2 MW. Our joint ownership interests include: a 1.7769 percent interest in an oil-generating plant in Maine; a 20 percent interest in a wood-, gas- and oil-fired generating plant in Vermont; a 1.7303 percent interest in a nuclear generating plant in Connecticut; and a 47.52 percent interest in a transmission interconnection facility in Vermont. Additional information with respect to these properties is set forth under Part I, Item 1, Business, Sources and Availability of Power Supply and is incorporated herein by reference.

At December 31, 2008, our electric transmission and distribution systems consisted of approximately 617 miles of overhead transmission lines, 8,460 miles of overhead distribution lines and 455 miles of underground distribution lines. All are located in Vermont except for approximately 23 miles in New Hampshire and 2 miles in New York.

Transco's properties consist of approximately 610 miles of high-voltage overhead and underground transmission lines and associated substations. The lines connect on the west with the lines of National Grid New York at the Vermont-New York border near Whitehall, N.Y., and Bennington, Vt., and with the submarine cable of New York Power Authority near Plattsburgh, N.Y.; on the south and east with the lines of National Grid New England, Public Service Company of New Hampshire and Northeast Utilities; on the south with the facilities of Vermont Yankee and with National Grid New England near Adams, Mass.; and on the northern border of Vermont with the lines of Hydro-Quebec near Derby, Vt. and through the Highgate converter station and tie line that we jointly own with several other Vermont utilities.

VELCO's wholly owned subsidiary, Vermont Electric Transmission Company, Inc. has approximately 54 miles of high-voltage DC transmission lines connecting with the transmission line of Hydro-Quebec at the Quebec-Vermont border in the Town of Norton, Vt.; and connecting with the transmission line of New England Electric Transmission Corporation, a subsidiary of National Grid USA, at the Vermont-New Hampshire border near New England Power Company's Moore hydroelectric generating station.

Item 3. Legal Proceedings

We are involved in legal and administrative proceedings in the normal course of business and 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.

Item 4. Submission of Matters to a Vote of Security Holders.

There were no matters submitted to security holders during the fourth quarter of 2008.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

(a) Our common stock is listed on the New York Stock Exchange ("NYSE") under the trading symbol CV.

The table below shows the high and low sales price of our Common Stock, as reported on the NYSE composite tape by The Wall Street Journal, for each quarterly period during the last two years as follows:

	Market Price	
2008	High	Low
First Quarter	$32.43	$22.40
Second Quarter	$25.13	$18.74
Third Quarter	$25.84	$18.17
Fourth Quarter	$24.37	$15.16
2007		
First Quarter	$29.19	$22.53
Second Quarter	$38.24	$29.10
Third Quarter	$41.05	$32.38
Fourth Quarter	$38.40	$25.95

(b) As of December 31, 2008, there were 6,221 holders of our Common Stock, $6 par value.

(c) Common Stock dividends have been declared quarterly and cash dividends of $0.23 per share were paid for all quarters of 2008 and 2007.

So long as any Senior Preferred Stock is outstanding, except as otherwise authorized by vote of two-thirds of such class, if the Common Stock Equity (as defined) is, or by the declaration of any dividend will be, less than 20 percent of Total Capitalization (as defined), dividends on Common Stock (including all distributions thereon and acquisitions thereof), other than dividends payable in Common Stock, during the year ending on the date of such dividend declaration, shall be limited to 50 percent of the Net Income Available for Dividends on Common Stock (as defined) for that year; and if the Common Stock Equity is, or by the declaration of any dividend will be, from 20 percent to 25 percent of Total Capitalization, such dividends on Common Stock during the year ending on the date of such dividend declaration shall be limited to 75 percent of the Net Income Available for Dividends on Common Stock for that year. The defined terms identified above are used herein in the sense as defined in subdivision 8A of our Articles of Association; such definitions are based upon our unconsolidated financial statements. As of December 31, 2008, the Common Stock Equity of our unconsolidated company was 53.1 percent of Total Capitalization.

Our First Mortgage Bond indenture contains certain restrictions on the payment of cash dividends on capital stock and other Restricted Payments (as defined). This covenant limits the payment of cash dividends and other Restricted Payments to our Net Income (as defined) for the period commencing on January 1, 2001 up to and including the month next preceding the month in which such Restricted Payment is to be declared or made, plus approximately $77.6 million. The defined terms identified above are used herein in the sense as defined in Section 5.09 of the Forty-Fourth Supplemental Indenture dated June 15, 2004; such definitions are based upon our unconsolidated financial statements. As of December 31, 2008, $64.1 million was available for such dividends and other Restricted Payments.

(d) The information required by this item is included in Part III, Item 12, Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, herein.

(e) The performance graph showing our five-year total shareholder return required by this item is included in our Annual Report to Shareholders and is hereby incorporated by reference.

Item 6. Selected Financial Data
(in thousands, except per share amounts)

	2008	2007	2006	2005	2004
Income Statement					
Operating revenues	$ **342,162**	$ 329,107	$ 325,738	$ 311,359	$ 302,286
Income from continuing operations (a)	$ **16,385**	$ 15,804	$ 18,101	$ 1,410	$ 7,493
Income from discontinued operations (b)	**0**	0	251	4,936	16,262
Net income	$ **16,385**	$ 15,804	$ 18,352	$ 6,346	$ 23,755
Per Common Share Data					
Basic earnings from continuing operations	$ **1.53**	$ 1.52	$ 1.65	$ 0.09	$ 0.59
Basic earnings from discontinued operations	**0.00**	0.00	0.02	0.40	1.34
Basic earnings per share	$ **1.53**	$ 1.52	$ 1.67	$ 0.49	$ 1.93
Diluted earnings from continuing operations	$ **1.52**	$ 1.49	$ 1.64	$ 0.08	$ 0.58
Diluted earnings from discontinued operations	**0.00**	0.00	0.02	0.40	1.32
Diluted earnings per share	$ **1.52**	$ 1.49	$ 1.66	$ 0.48	$ 1.90
Cash dividends declared per share of common stock	$ **0.92**	$ 0.92	$ 0.69	$ 1.15	$ 0.92
Balance Sheet					
Long-term debt (c)	$ **167,500**	$ 112,950	$ 115,950	$ 115,950	$ 115,950
Capital lease obligations (c)	$ **5,173**	$ 5,889	$ 6,612	$ 6,153	$ 7,094
Redeemable preferred stock (c)	$ **1,000**	$ 2,000	$ 3,000	$ 4,000	$ 6,000
Total capitalization (c)	$ **401,206**	$ 317,700	$ 312,968	$ 351,527	$ 361,751
Total assets	$ **621,126**	$ 540,314	$ 500,938	$ 551,433	$ 563,389

(a) For 2005 includes a $21.8 million pre-tax charge to earnings ($11.2 million after-tax) related to a 2005 Rate Order.
For 2004 includes a $14.4 million pre-tax charge to earnings ($8.4 million after-tax) related to termination of a long-term power contract with Connecticut Valley as a result of the January 1, 2004 sale of substantially all of its assets and franchise.
(b) For 2006 and 2005 includes Catamount, which was sold in the fourth quarter of 2005. For 2004 includes Catamount and Connecticut Valley.
(c) Amounts exclude current portions.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

In this section we discuss our general financial condition and results of operations. Certain factors that may impact future operations are also discussed. Our discussion and analysis is based on, and should be read in conjunction with, the accompanying Consolidated Financial Statements. The discussion below also includes non-GAAP measures referencing earnings per diluted share for variances described below in Results of Operations. We use this measure to provide additional information and believe that this measurement is useful to investors to evaluate the actual performance and contribution of our business activities. This non-GAAP measure should not be considered as an alternative to our consolidated fully diluted earnings per share determined in accordance with GAAP as an indicator of our operating performance. Also, please refer to our "Cautionary Statement Regarding Forward-Looking Information" section preceding Part I, Item 1, Business of this Form 10-K.

COMPANY OVERVIEW

Our core business is the Vermont electric utility business. We typically generate most of our earnings through retail electricity sales. We also sell excess power, if any, to third parties in New England and to ISO-New England. The resale revenue generated from these sales helps to mitigate our power supply costs.

We are regulated by the Vermont Public Service Board ("PSB"), the Connecticut Department of Public Utility Control and the Federal Energy Regulatory Commission ("FERC"), with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. Our non-regulated wholly owned subsidiary Catamount Resources Corporation ("CRC") owns Eversant Corporation ("Eversant"), which operates a rental water heater business through its wholly owned subsidiary, SmartEnergy Water Heating Services, Inc. This is not a significant business activity for us.

As a regulated electric utility, we have an exclusive right to serve customers in our service territory, which can generally be expected to result in relatively stable revenue streams. The ability to increase our customer base is limited to acquisitions or growth within our service territory. Due to the nature of our customer base, weather and economic conditions are factors that can significantly affect retail sales revenue. Retail sales volume over the last 10 years has grown at an average rate of less than 1 percent per year, ranging from a decrease of over 2 percent in 2008 to increases of over 2 percent in other years. We currently have sufficient power resources to meet or exceed our forecasted load requirements through 2011.

EXECUTIVE SUMMARY

Our consolidated 2008 earnings were $16.4 million, or $1.52 per diluted share of common stock. This compares to consolidated 2007 earnings of $15.8 million, or $1.49 per diluted share of common stock, and consolidated 2006 earnings of $18.4 million, or $1.66 per diluted share of common stock. The primary drivers of earnings variances for the three years are described in Results of Operations below.

A December 2008 ice storm did unprecedented damage to significant portions of our electrical system in rugged, rural sections of southern and eastern Vermont. The restoration effort resulted in our most expensive storm recovery with costs of more than $5 million, exceeding the repair costs we incurred as a result of the so-called Nor'icane of 2007, previously the most expensive storm in our history with incremental storm restoration costs totaling $3.5 million. Our rates include a five-year average of storm restoration costs, but given the magnitude of the ice storm, that average will not fully recover our current costs. We filed a motion with the PSB to allow us to defer the portion of the ice storm recovery costs not reflected in rates, and to recover those costs over a one-year period beginning July 1, 2009. On February 12, 2009, the PSB approved our request to defer $4.1 million of costs related to the ice storm.

The global decline in the equity markets has affected the value of our employee benefit and nuclear decommissioning trust funds and the cash surrender value of life insurance policies included in our Rabbi Trust. The fair value of our pension and postretirement trust fund investments decreased $16.3 million during 2008, principally due to the decline in the equity markets. Changes in the value of these trust fund assets did not have an impact on the income statement for 2008; however, reduced trust fund asset values will result in increased benefit costs in future years and may increase the amount and accelerate the timing of required future funding contributions. During 2008, the value of our Millstone Unit #3 nuclear decommissioning trust fund decreased by $1.4 million, and the cash surrender value of certain insurance policies included in our Rabbi Trust decreased by $2 million, principally due to the downturn of the equity markets. These declines are offset on the Consolidated Balance Sheets, in Regulatory liabilities. See Results of Operations, Liquidity and Capital Resources, Pension and Postretirement Medical Plan below for additional information.

Restoring our corporate credit rating to investment grade is a top priority for us. During 2008, we made progress on several key strategic financial initiatives including:

- On May 15, 2008, we issued $60 million of our First Mortgage 6.83% Bonds, Series UU due May 15, 2028. We used the proceeds of this offering to repay a $53 million note that was due on June 30, 2008 and for general corporate purposes. We are evaluating other financing options to support current and future working capital needs resulting from investments in our distribution and transmission system and optional future investments in Vermont Transco LLC ("Transco"), the Vermont company that owns and operates the high-voltage transmission system in Vermont.
- On September 30, 2008, the PSB issued an order approving, with modifications, the alternative regulation plan proposal that we submitted in August 2007. The plan became effective on November 1, 2008. It expires on December 31, 2011, but we have an option to petition for an extension beyond 2011. The plan replaces the traditional ratemaking process and allows for annual base rate adjustments, quarterly rate adjustments to reflect changes in power supply and transmission-by-others cost changes and annual rate adjustments to reflect changes, within predetermined limits, from the allowed earnings level. See Retail Rates and Alternative Regulation.
- In November 2008, we issued 1,190,000 shares of common stock. We used the net proceeds of the offering for general corporate purposes, including the repayment of debt, capital expenditures, investments in Transco and working capital requirements.
- In December 2008, we made a $3.1 million investment in Transco. This increased our equity investment in Transco to $87.6 million at December 31, 2008. See Liquidity, Capital Resources and Commitments.

Other financial initiatives that we continue to focus on include maintaining sufficient liquidity to support ongoing operations, the dividend on our common stock, investing 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 restoring our corporate credit rating to investment grade. 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 set by the Vermont Public Service Board ("PSB") after considering the recommendations of Vermont's consumer advocate, the Vermont Department of Public Service ("DPS"). Fair regulatory treatment is fundamental to maintaining our financial stability. Rates must be set at levels to recover costs, including a market rate of return to equity and debt holders, in order to attract capital. The return on common equity of our regulated business did not exceed the allowed return for 2008, 2007 or 2006.

On January 31, 2008, the PSB approved a settlement agreement that we previously reached with the Vermont Department of Public Service ("DPS"). The settlement included, among other things, a 2.30 percent rate increase (additional revenue of $6.4 million on an annual basis) effective February 1, 2008 and a 10.71 percent rate of return on equity, capped until our next rate proceeding or approval of the alternative regulation plan proposal that we submitted on August 31, 2007. We also agreed to conduct an independent business process review to assure our cost controls are sufficiently challenging and that we are operating efficiently.

The business process review commenced in April 2008 and concluded in October 2008. The final report, which was generally positive about company operations, included 51 recommendations for improvement covering a wide range of areas in the company. We are collaborating on the implementation of these recommendations with the DPS and we have filed an implementation update with the PSB. The cost of the review, approximately $0.4 million, did not affect our income statement because the costs have been deferred for future recovery in rates.

On September 30, 2008, the PSB issued an Order approving, with modifications, the alternative regulation plan proposal that we submitted in August 2007. The plan became effective on November 1, 2008. It expires on December 31, 2011, but we have an option to petition for an extension beyond 2011. The plan replaces the traditional ratemaking process and allows for annual base rate adjustments, quarterly rate adjustments to reflect changes in power supply and transmission-by-others costs and annual rate adjustments to reflect changes, within predetermined limits, from the allowed earnings level. The allowed return on equity was reduced from 10.71 percent to 10.21 percent as of the effective date of the plan, per a settlement agreement that we reached with the DPS. Under the plan, the allowed return on equity will be adjusted annually to reflect one half of the change in the yield on the 10-year Treasury note as measured over the last 20 trading days prior to October 15 of each year. The earnings sharing adjustment mechanism within the plan provides for the return on equity of the regulated portion of our business to fall between 75 basis points above or below the allowed return on equity before any adjustment is made. If the actual return on equity of the regulated portion of our business exceeds 75 basis points above the allowed return, the excess amount is returned to ratepayers in a future period. If the actual return on equity of our regulated business falls between 75 and 100 basis points below the allowed return on equity, the shortfall is shared equally between shareholders and ratepayers. Any earnings shortfall in excess of 100 basis points below the allowed return on equity is recovered from ratepayers. These adjustments are made at the end of each fiscal year.

The plan encourages efficiency in operations. It also includes provisions for us to contribute, under certain circumstances, to a to-be-established low-income bill-assistance program; to develop an annual fixed-power-price option for retail consumers; and to track and report annually on the number of retail customers affected by supplier-caused outages. In its Order, the PSB also approved a previous settlement that we reached with the Conservation Law Foundation, a regional environmental advocacy organization. That settlement included: 1) implementing automated metering infrastructure, which we refer to as CVPS SmartPower™, as quickly as we reasonably can under a timetable to be approved by the PSB; 2) introducing demand response programs for all customer classes; 3) advancing Vermont-based renewable power generation; and 4) working with the DPS and Vermont Energy Efficiency Utility ("EEU"), which is charged with implementing energy efficiency programs throughout Vermont, to develop and implement an EEU program to promote installation of efficient heating systems such as solar thermal hot-water systems, small combined-heat and-power systems and cost-effective heat pumps.

On October 10, 2008, we filed a Motion for Reconsideration and Clarification with the PSB requesting clarification and amendments to certain portions of its Order that created uncertainty and had the potential to create significant disputes in the administration of our plan. On October 15, 2008, the DPS filed its response to our motion. On October 23, 2008, the PSB issued a favorable order on our motion. The PSB clarified that, among other things, the quarterly power adjustments and annual earnings sharing adjustments will commence on January 1, 2009 with the first power adjustment filing due on May 1, 2009, for effect on July 1, 2009.

On October 31, 2008, we filed a revised and restated alternative regulation plan incorporating the provisions in the PSB Orders. We also submitted a base rate filing for the rate year commencing January 1, 2009 that reflected a 0.33 percent increase in retail rates. The result of the return on equity adjustment for 2009, as measured in accordance with the plan, was a reduction of 0.44 percent, resulting in an allowed return on equity for 2009 of 9.77 percent.

On November 17, 2008, the DPS filed a request for suspension and investigation of our filing. Citing concerns about staffing levels and inadequate supporting documentation for some proposed plant additions, the DPS recommended a 0.43 percent rate decrease. On November 25, 2008, the PSB issued an order allowing our rate increase request of 0.33 percent effective January 1, 2009, and also opened an investigation to determine whether the 2009 rates are just and reasonable.

On December 17, 2008, we filed with the PSB a Memorandum of Understanding setting forth agreements that we reached with the DPS regarding the PSB's investigation into our 2009 retail rates. Pursuant to the Memorandum of Understanding, we agreed to hold rates flat, with no increase or decrease, and that we and the DPS would request the PSB to open a docket to resolve the DPS's concerns regarding our level of staffing. On February 13, 2009, the PSB approved the Memorandum of Understanding, ordered the rate investigation closed, and opened a docket to investigate the Company's staffing levels. The outcome of the staffing level investigation cannot be predicted at this time.

On February 2, 2009, we filed a motion with the PSB to recover through our alternative regulation plan approximately $4.1 million of extraordinary storm costs incurred in December 2008. On February 3, 2009, the DPS filed a letter supporting our motion. On February 12, 2009, the PSB approved the request. Accordingly, the December 2008 storm cost recovery and amortization will begin on July 1, 2009.

Our retail rates at December 31, 2007 were based on a December 7, 2006 PSB Order approving, among other things, a 4.07 percent rate increase effective January 1, 2007 and an allowed rate of return on common equity of 10.75 percent capped until our next rate proceeding. Our regulated business did not exceed the allowed return for 2007. At the time the order was issued, we had a pending Accounting Order request for recovery of $1.5 million of incremental replacement power costs subject to PSB approval. On January 12, 2007, the PSB denied our Accounting Order request. This outcome had no 2006 income statement impact since the incremental replacement power costs were previously expensed in 2005, and it did not change the 4.07 percent rate increase effective January 1, 2007. Pursuant to the December 2006 order, we deferred $0.8 million of revenue, which was returned to customers, over a 12-month period, in the new rates effective February 1, 2008.

Our retail rates for 2006 were based on a March 29, 2005 PSB Order that provided for a 2.75 percent rate decrease and an allowed rate of return on common equity capped at 10 percent.

LIQUIDITY, CAPITAL RESOURCES AND COMMITMENTS

Cash Flows At December 31, 2008, we had cash and cash equivalents of $6.7 million and at December 31, 2007, we had cash and cash equivalents of $3.8 million. The primary components of cash flows from operating, investing and financing activities for both periods are discussed in more detail below.

Operating Activities: Operating activities provided $28.4 million in 2008. Net income, when adjusted for depreciation, amortization, deferred income tax and other non-cash income and expense items, provided $51.1 million. This included $10.7 million of distributions received from affiliates, most materially from our investments in Transco. In addition, changes in working capital and other items used $22.7 million. This was primarily due to $7.9 million of employee benefit funding, including $6.2 million of pension and postretirement medical trust fund contributions, and $3.6 million of special deposits and restricted cash used to meet performance assurance requirements for certain power contracts. We replaced letters of credit to meet collateral requirements with cash.

Operating activities provided $34.1 million in 2007. Net income, when adjusted for depreciation, amortization, deferred income tax and other non-cash income and expense items, provided $38.8 million. This amount was offset by operating activities related to working capital and other items that used $4.7 million. These items primarily included employee benefit funding of $7.9 million, of which $6.7 million was used for pension and postretirement medical trust fund contributions. This was offset by a $3.5 million decrease in special deposits and restricted cash used to meet performance assurance requirements for certain power contracts because we replaced cash deposited to meet collateral requirements with $1.5 million of additional letters of credit.

Investing Activities: Investing activities used $40.5 million in 2008, including $36.8 million for construction and plant expenditures, $3.1 million for our investment in Transco and $0.6 million for other investments. The majority of the construction and plant expenditures were for system reliability, performance improvements and customer service enhancements.

During 2007, investing activities used $76.6 million, including $23.7 million for construction and plant expenditures and $53 million for our investment in Transco, partially offset by $0.1 million from other investments. The majority of the construction and plant expenditures were for system reliability, performance improvements and customer service enhancements.

Financing Activities: Financing activities provided $15 million in 2008. We received $60 million of proceeds from the issuance of long-term debt and $23.5 million from the issuance of 1,190,000 shares of common stock ($17.86 per share), exercised stock options and the dividend reinvestment program. These items were partially offset by a $53 million repayment of a short-term bridge loan, $9.9 million for dividends paid on common and preferred stock, $3 million redemption of first mortgage bonds, $1 million of debt issuance and deferred common stock offering costs, $1 million in preferred stock sinking fund payments, and $0.6 million of Other financing activities that includes $0.9 million for capital lease payments.

Proceeds of $9.3 million from borrowings under our short-term credit facility and $3.4 million from letters of credit supporting remarketed bonds were provided and repaid during the period. Also, see Financing below.

During 2007, financing activities provided $43.5 million. This was comprised of a $53 million short-term bridge loan and $2.1 million of stock issuance proceeds resulting from exercised stock options and the dividend reinvestment program. These items were partially offset by $9.7 million for dividends paid on common and preferred stock, $1 million in preferred stock sinking fund payments, and $0.9 million for capital lease payments. Also, see Financing below.

Transco In October 2007, Transco received PSB approval to issue up to $113.8 million of equity. In December 2007, we invested $53 million in Transco, increasing our direct equity interest in Transco from 29.86 percent to 39.79 percent. Our total direct and indirect interest in Transco increased from 44.34 percent to 45.68 percent. In October 2008, Transco received PSB approval to issue up to $93.4 million of equity. In December 2008, we invested an additional $3.1 million in Transco and our direct ownership interest decreased from 39.79 percent to 33.02 percent as a result of additional member contributions from Vermont utilities related to specific facilities. Our total direct and indirect interest in Transco decreased from 45.68 percent to 39.67 percent.

Based on current projections, Transco expects to receive additional capital in 2009, 2010 and 2011, but its projections are subject to change based on a number of factors, including revised construction estimates, timing of project approvals from regulators, and desired changes in its equity-to-debt ratio. While we have no obligation to make additional investments in Transco, we continue to evaluate investment opportunities on a case-by-case basis. Based on Transco's current projections, we could have an opportunity to make additional investments of up to $21 million in 2009, $24 million in 2010 and $13 million in 2011, but the timing and amount depend on the factors discussed above and the amounts invested by other owners.

We are currently evaluating 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.

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 was reinstated in April 2007. At that time, we elected to change the source of common shares to meet reinvestment needs under the plan from open market purchases to original issue shares. In July 2007, we began using treasury shares to meet reinvestment needs under the plan. These elections are expected to result in additional cash flow of $1 million to $2 million annually.

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

Global Economic Crisis Due to the global economic crisis, there has been a significant decline in lending activity. We expect to have access to liquidity in the capital markets at reasonable rates. We also have access to a $40 million unsecured revolving credit facility. However, sustained turbulence in the global credit markets could limit or delay our access to capital.

Financing

Long-Term Debt: Substantially all of our utility property and plant are subject to the lien under our First Mortgage Indenture. Associated scheduled sinking fund payments for the next five years are: $5.5 million in 2009, zero in 2010, $20 million in 2011, zero in 2012 and zero in 2013. Currently, we are in compliance with the terms of all of our debt financing documents.

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. This replaced the previous 364-day, $25 million credit facility that was to expire in October 2008. Our obligation under the credit agreement is guaranteed by our wholly owned, unregulated subsidiaries, C.V. Realty and CRC. The purpose of the facility is to provide liquidity for general corporate purposes, including working capital needs and power contract performance assurance requirements, in the form of funds borrowed and letters of credit. Financing terms and costs include an annual commitment fee of 0.225 percent on the unused balance, plus interest on the outstanding balance of amounts borrowed at various interest options and a commission of 0.9 percent on the average daily amount of letters of credit outstanding. All interest, commission and fee rates are based on our unsecured long-term debt rating. The facility contains a material adverse effect clause, exercisable when our corporate credit rating falls below investment grade, which permits the lender to deny a transaction at the point of request. Our corporate credit rating is currently categorized as below investment grade. We are also required to collateralize any outstanding letter of credit in the event of a default under the credit facility. At December 31, 2008, there were no borrowings or letters of credit outstanding under the credit facility. Under the old credit facility, a $5 million letter of credit, formerly in support of performance assurance requirements with a power trading counterparty, was outstanding until early January 2008.

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

Letters of Credit: We have three outstanding secured letters of credit issued by one bank, totaling $16.9 million in support of three separate issues of industrial development revenue bonds totaling $16.3 million. We pay an annual fee of 0.9 percent on the letters of credit, based on our secured long-term debt rating. On September 26, 2008, we extended the maturities of these letters of credit to November 30, 2009. The letters of credit are secured under our first mortgage indenture. At December 31, 2008, there were no amounts drawn under these letters of credit.

Covenants: At December 31, 2008, we were in compliance with all financial covenants related to our various debt agreements, articles of association, letters of credit, credit facility and material agreements. A significant reduction in future earnings or a significant reduction to common equity could restrict the payment of common and preferred dividends or could cause us to violate our maintenance covenants. If we were to default on our covenant, the lenders could take such actions as terminate their obligations, declare all amounts outstanding or due immediately payable, or take possession of or foreclose on mortgaged property.

Capital Commitments Our business is capital-intensive because annual construction expenditures are required to maintain the distribution system. Capital expenditures in 2008 amounted to $36.8 million. Capital expenditures for the next five years are expected to range from $32 million to $62 million annually, including an estimated total of $42 million for CVPS SmartPower™ over the 5-year period. The increased spending levels reflect our continued commitment to invest in system upgrades. These estimates are subject to continuing review and adjustment, and actual capital expenditures and timing may vary.

Contractual Obligations Significant contractual obligations as of December 31, 2008 are summarized below.

	Payments Due by Period (dollars in millions)				
Contractual Obligations	Total	Less than 1 year	1 - 3 years	3 - 5 years	After 5 years
Long-term debt	$ 173.0	$ 5.5	$ 20.0	$ 0.0	$ 147.5
Interest on long-term debt (a)	163.7	11.0	21.0	19.6	112.1
Notes payable (b)	10.8	10.8	0.0	0.0	0.0
Interest on notes payable (a)	0.6	0.1	0.2	0.2	0.1
Redeemable preferred stock	2.0	1.0	1.0	0.0	0.0
Capital lease (c)	7.9	1.4	2.6	2.2	1.7
Operating leases - vehicle and other (d)	11.0	9.0	0.7	0.7	0.6
Purchased power contracts (e)	831.7	148.2	294.0	170.0	219.5
Nuclear decommissioning and other closure costs (f)	10.0	1.4	3.1	3.2	2.3
Total Contractual Obligations	$ 1,210.7	$ 188.4	$ 342.6	$ 195.9	$ 483.8

(a) Based on interest rates shown in Note 13 - Long-Term Debt and Note 14 - Notes Payable and Credit Facility.
(b) Notes payable are contingent on both puts and remarketing; therefore, are recorded as current liabilities.
(c) Includes interest payments based on imputed fixed interest rates at inception of the related leases.
(d) Includes interest payments on fixed rates at inception and floating rate issues based on interest rates as of December 31, 2008.
(e) Forecasted power purchases under long-term contracts with Hydro-Quebec, VYNPC and various Independent Power Producers. Our current retail rates include a provision for recovery of these costs from customers. The forecasted amounts in this table are based on certain assumptions including plant operations, weather conditions, market power prices and availability of the transmission system, therefore actual results may differ. See Power Supply Matters for more information.
(f) Estimated decommissioning and all other closure costs related to our equity ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. Our current retail rates include a provision for recovery of these costs from customers.

Pension and Postretirement Medical Benefit Obligations: The contractual obligation table above excludes estimated funding for the pension obligation reflected in our Consolidated Balance Sheet. These payments may vary based on changes in the fair value of plan assets and actuarial assumptions. In 2009, pending further review, we expect to contribute a total of $6.7 million to our pension and postretirement medical trust funds; however, there is no minimum funding requirement for our pension plan in 2009. Based on our current funding level, we do not expect the provisions of the Pension Protection Act of 2006, passed into law in August 2006, to have a significant impact on our minimum required contributions in the near future. We expect that pension and postretirement medical contributions will not significantly exceed current funding levels for 2010 through 2012. Additional obligations related to our nonqualified pension plans are approximately $0.3 million per year.

Income Taxes: The following FIN 48 liabilities are excluded from the Contractual Obligations Table. At December 31, 2008, unrecognized state tax benefits of $0.6 million were recorded as FIN 48 liabilities. We are unable to make reasonably accurate estimates of the period of cash settlement, if any, and the statute of limitations might expire without examination by the respective state taxing authority. These amounts are not currently subject to an examination by the state taxing authority. Also, at December 31, 2008, unrecognized federal tax benefits of $1.1 million were recorded as FIN 48 liabilities. These unrecognized tax benefits relate to taxes receivable for which the refunds relating to the unrecognized tax benefits have not been received. Consequently, if the claim is denied there will be no refund forthcoming, and also no future cash outflow.

Capitalization Our capitalization for the past two years follows:

	(dollars in thousands)		Percent	
	2008	2007	**2008**	2007
Common stock equity	219,479	$ 188,807	55%	59%
Preferred stock	9,054	10,054	2%	3%
Long-term debt	167,500	112,950	42%	36%
Capital lease obligations	5,173	5,889	1%	2%
	$ 401,206	$ 317,700	100%	100%

Credit Ratings On December 22, 2008, Standard and Poor's Ratings Services ("S&P") reaffirmed our BB+ corporate credit rating (below investment grade), our BBB+ senior secured bond rating and stable outlook. Our current credit ratings from S&P are shown in the table below. Credit ratings should not be considered a recommendation to purchase or sell stock.

Corporate Credit Rating	BB+
First Mortgage Bonds	BBB+
Preferred Stock	B+
Outlook	Stable

Our credit ratings are influenced by our levels of cash flow and debt, and other factors published by S&P. If our corporate credit rating were to decline further, we could be asked to provide additional collateral in the form of cash or letters of credit. As of December 31, 2008, an additional decline in our corporate credit rating would not have required us to provide additional collateral to unaffiliated counterparties or to ISO-New England. While our credit facilities are sufficient in amounts that would be required to meet collateral calls at a higher level, our ability to meet any future collateral calls would depend on our liquidity and access to bank credit lines and the capital markets at such time. Additionally, a further decline in our corporate credit rating could jeopardize our ability to secure power contracts, including the replacement of our long-term power contracts, at reasonable terms.

Performance Assurance At December 31, 2008, we had posted $6.9 million of collateral under performance assurance requirements for certain of our power contracts, of which $3.3 million was unrestricted cash and $3.6 million was restricted cash. We are subject to performance assurance requirements through ISO-New England under the FERC-filed tariff and Financial Assurance Policy for NEPOOL members. We are required to post collateral for all net purchased power transactions since our credit limit with ISO-New England is zero. Additionally, we are currently selling power in the wholesale market pursuant to contracts with third parties, and are required to post collateral under certain conditions defined in the contracts.

We are also subject to performance assurance requirements under our Vermont Yankee power purchase contract (the 2001 Amendatory Agreement). If Entergy Nuclear Vermont Yankee, LLC ("Entergy-Vermont Yankee"), the seller, has commercially reasonable grounds to question our ability to pay for 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. Additionally, until October 24, 2008, we leased our vehicles and related equipment under one operating lease agreement. The individual leases under this agreement are mutually cancelable one year from lease inception. Under the terms of the vehicle operating lease, we have guaranteed a residual value to the lessor in the event the leased items are sold. The guarantee provides for reimbursement of up to 87 percent of the unamortized value of the lease portfolio. Under the guarantee, if the entire lease portfolio had a fair value of zero at December 31, 2008, we would have been responsible for a maximum reimbursement of $7.3 million. On November 14, 2008, we received notification from the lessor that this lease agreement was being terminated. Under the terms of the lease, we will be required to terminate all vehicle leases by November 14, 2009 and pay the lessor the unamortized value of the equipment upon termination, either by purchasing the equipment or through the sale of the equipment to a third party. The estimated unamortized value of the equipment on the termination date of November 14, 2009 is $6.4 million. We will evaluate adding the equipment being terminated under this lease to a lease agreement with another lessor.

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

Commitments and Contingencies We have material power supply commitments for the purchase of power from VYNPC and Hydro-Quebec. 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. We own an equity interest in VYNPC and are obligated to pay a portion of VYNPC's operating costs. We also own equity interests in three nuclear plants that are permanently shut down and have completed decommissioning activities. We are responsible for paying our share of the costs associated with these plants. Our equity ownership interests are described inPart II, Item 8, Note 3 - Investments in Affiliates.

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 Part II, Item 8, Note 17 - Commitments and Contingencies.

OTHER BUSINESS RISKS

In addition to the risks described above, 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. Hydro-Quebec contract deliveries end in 2016, but the average level of deliveries decreases by approximately 20 percent to 30 percent after 2012, and by approximately 85 percent after 2015. 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.

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

There is also a risk that the Vermont Yankee plant could be shut down earlier than expected if Entergy-Vermont Yankee determines that it is not economical to continue operating the plant. An early shutdown would cause us to lose the economic benefit of an energy volume of close to 50 percent of our total committed supply and we would have to acquire replacement power resources for approximately 40 percent of our estimated power supply needs. Based on projected market prices as of December 31, 2008, the incremental replacement cost of lost power, including capacity, is estimated to average $37.5 million annually. 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 any such shutdown. However, an early shutdown could materially impact our financial position and future results of operations if the costs are not recovered in retail rates in a timely fashion. The Power Cost Adjustment Mechanism within our alternative regulation plan will allow more timely recovery of power costs for 2009, 2010 and 2011.

Beginning in 2007, we, Green Mountain Power, and HQ-Production created a steering committee structure to develop background materials, terms and supporting actions needed in negotiations for future power purchases from Hydro-Quebec. Beginning in May 2008, HQ-Production also engaged with Northeast Utilities ("NU") and NSTAR on a plan to bundle a new 1,200 MW New England/Quebec interconnection and power purchase agreement and have submitted the concept to the FERC for approval in early 2009. HQ-Production and NU have expressed the expectation that there will be sufficient volume in that bundled power purchase agreement to allow the participation of other load-serving New England utilities to participate, including Vermont utilities. The Vermont utilities now expect to join in the negotiations of the agreement, which are scheduled to conclude by mid-2009. Agreements to renew purchases over existing interconnections are also possible. We cannot predict whether a new contract will ultimately be achieved and approved or if approved, the quantities of power to be purchased or the price terms of any purchases.

Wholesale Power Market Price Risk: Our material power supply contracts are with Hydro-Quebec 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 31, 2009 to cover additional costs, if any, of obtaining replacement power from other sources if the Vermont Yankee plant experiences unplanned outages. We are currently working with an insurance broker to obtain insurance coverage for the remainder of 2009 through March of 2012. The Power Cost Adjustment Mechanism within our alternative regulation plan will allow recovery of power costs for 2009, 2010 and 2011.

Market Risk: See Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements, and reported amounts of revenues and expenses during the reporting period. We believe that the areas described below require significant judgment in the application of accounting policy or in making estimates and assumptions in matters that are inherently uncertain and that may change in subsequent periods.

Regulatory Accounting We prepare our financial statements in accordance with SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71") for our regulated business. Regulatory assets or liabilities arise as a result of a difference between accounting principles generally accepted in the U.S. and the accounting principles imposed by the regulatory agencies. Generally, regulatory assets represent incurred costs that have been deferred as they are probable of recovery in future rates. In some circumstances, we record regulatory assets before approval for recovery has been received from the regulatory commission. We must use judgment to conclude that costs deferred as regulatory assets are probable of future recovery. We base our conclusions on a number of factors such as, but not limited to, changes in the regulatory environment, recent rate orders issued and the status of any potential new legislation. Regulatory liabilities represent obligations to make refunds to customers or amounts collected in rates for which the costs have not yet been incurred.

The assumptions and judgments used by regulatory authorities may have an impact on the recovery of costs, the rate of return on invested capital and the timing and amount of assets to be recovered by rates. A change in these assumptions may have a material impact on our results of operations. In the event that we determine our regulated business no longer meets the criteria under SFAS No. 71 and there is not a rate mechanism to recover these costs, the impact would, among other things, be an extraordinary charge to operations of $8.9 million pre-tax at December 31, 2008. The continued applicability of SFAS No. 71 is assessed at each reporting period. We believe our regulated operations will be subject to SFAS No. 71 for the foreseeable future. Also, see Recent Accounting Pronouncements below.

Valuation of Long-Lived Assets We periodically evaluate the carrying value of long-lived assets, including our investments in nuclear generating companies, our unregulated investments, and our interests in jointly owned generating facilities, when events and circumstances warrant such a review. The carrying value of such assets is considered impaired when the anticipated undiscounted cash flow from such an asset is separately identifiable and is less than its carrying value. In that event, a loss is recognized based on the amount by which the carrying value exceeds the fair value of the long-lived asset. No impairments of long-lived assets were recorded in 2008 or 2007.

Revenues Revenues from the sale of electricity to retail customers are based on PSB-approved rates. Our revenues are recorded when service is rendered or when energy is delivered to customers. We accrue revenue based on estimates of electric service rendered and unbilled revenue at the end of each accounting period. This unbilled revenue is estimated each month based on daily generation volumes (territory load), estimated line losses and applicable customer rates. We estimate line losses at 5 percent. A 1 percent change in line losses would result in a $2.8 million change in revenues. Factors that could affect the estimate of unbilled revenues include seasonal weather conditions, changes in meter reading schedules, the number and type of customers scheduled for each meter reading date, estimated customer usage by class, applicable customer rates and estimated losses of energy during transmission and delivery. We believe that these assumptions have been a reasonable approximation of our unbilled revenues and the assumptions are reasonably likely to continue. Unbilled revenues totaled $18.5 million at December 31, 2008 and $17.7 million at December 31, 2007. We believe that these assumptions have been a reasonable approximation of our unbilled revenues and the assumptions are reasonably likely to continue.

Pension and Postretirement Medical Benefits FASB Statement No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)* ("SFAS No. 158") requires an employer with a defined benefit plan or other postretirement plan to recognize an asset or liability on its balance sheet for the overfunded or underfunded status of the plan.

SFAS No. 158 also required companies with early benefit measurement dates to change their measurement date in 2008 to correspond with their fiscal year-end and to record the financial statement impact of the change as an adjustment to retained earnings. We estimated that changing the annual benefit measurement date from September 30 to December 31 would result in a pre-tax charge of $1.3 million, of which $0.1 million was recorded to retained earnings. In our recent retail rate proceeding we received approval for recovery of the regulated utility portion of the impact resulting from the change in measurement date. Accordingly, we recorded a regulatory asset of $1.2 million in the first quarter of 2008 that is being amortized over five years, beginning in February 2008.

We use the fair value method to value all asset classes included in our pension and postretirement medical benefit trust funds. Assumptions are made regarding the valuation of benefit obligations and performance of plan assets. Delayed recognition of differences between actual results and those assumed is a required principle of these standards. This approach allows for systematic recognition of changes in benefit obligations and plan performance over the working lives of the employees who benefit under the plans. The following assumptions are reviewed annually, with a December 31 measurement date:

Discount Rate: The discount rate is used to record the value of benefits, which are based on future projections, in terms of today's dollars. The selection methodology used in determining the discount rate includes portfolios of "Aa" bonds; all are United States issues and non-callable (or callable with make-whole features) and each issue is at least $50 million in par value. As of December 31, 2008, the pension discount rate changed from 6.30 percent to 6.15 percent and the postretirement medical discount rate changed from 6.15 percent to 6.05 percent. The current conditions in the credit market are volatile and decreases in the discount rates could negatively increase our benefit obligations, which may also result in higher costs and funding requirements. We believe that the discount rates for the Pension and Postretirement Medical obligations are appropriate annual assumptions.

Expected Return on Plan Assets ("ROA"): We project the future ROA based principally on historical returns by asset category and expectations for future returns, based in part on simulated capital market performance over the next 10 years. The projected future value of assets reduces the benefit obligation a company will record. The expected ROA as of September 30, 2007 and 2008 was 8.25 percent. This rate was used to determine the annual expense for 2008. An expected ROA of 7.85 percent will be used to determine the 2009 expense. The current conditions in the credit market could negatively impact the assets in our trusts, but at this time we believe that the 7.85 percent rate for Pension and Postretirement Medical plan assets is an appropriate long-term rate of return assumption.   We will continue to evaluate the rate at least annually, and will adjust it as necessary.

Rate of Compensation Increase: We project employees' compensation increases, including annual increases, promotions and other pay adjustments, based on our expectations for future long-term experience reflecting general trends. This projection is used to estimate employees' pension benefits at retirement. The projected rate of compensation increase was 4.25 percent as of the measurement date in 2007 and 2008. We will continue to evaluate the rate at least annually, and will adjust it as necessary.

Health Care Cost Trend: We project expected increases in the cost of health care. For measurement purposes, we assumed a 9.0 percent annual rate of increase in the per capita cost of covered health care benefits for fiscal 2008, for pre-age 65 and post-age 65 claims costs. The rate is assumed to decrease 0.5 percent each year, until an ultimate rate of 5.0 percent is reached in 2016. We will continue to evaluate the rate at least annually, and will adjust it as necessary.

Amortization of Gains/(Losses): The assets and liabilities of the pension and postretirement medical benefit plans are affected by changing market conditions as well as differences between assumed and actual plan experience. Such events result in gains and losses. Investment gains and losses are deferred and recognized in pension and postretirement medical benefit costs over a period of years. If, as of the annual measurement date, the plan's unrecognized net gain or loss exceeds 10 percent of the greater of the projected benefit obligation or the market-related value of plan assets, the excess is amortized over the average remaining service period of active plan participants. This 10-percent corridor method helps to mitigate volatility of net periodic benefit costs from year to year. Asset gains and losses related to certain asset classes such as equity, emerging-markets equity, high-yield debt and emerging-markets debt are recognized in the calculation of the market-related value of assets over a five-year period. The fixed income assets are invested in longer-duration bonds to match changes in plan liabilities. The gains and losses related to this asset class are recognized in the market-related value of assets immediately. Also see Part II, item 8, Note 15 - Pension and Postretirement Medical Benefits.

Pension and Postretirement Medical Assumption Sensitivity Analysis Fluctuations in market returns may result in increased or decreased pension costs in future periods. The table below shows how, hypothetically, a 25-basis-point change in discount rate and expected return on assets would affect pension costs (dollars in thousands):

	Discount Rate		Return on Assets	
	Increase	**Decrease**	**Increase**	**Decrease**
Pension Plan				
Effect on accumulated benefit obligation as of December 31, 2008	$ (1,816)	$ 1,851	$ 0	$ 0
Effect on 2008 net period benefit cost	$ (19)	$ 13	$ (222)	$ 222
Other Postretirement Medical Benefit Plans				
Effect on accumulated benefit obligation as of December 31, 2008	$ (706)	$ 722	$ 0	$ 0
Effect on 2008 net periodic benefit cost	$ (77)	$ 77	$ (32)	$ 33

Fair Value Measurements We adopted SFAS 157, *Fair Value Measurements* ("SFAS 157"), on January 1, 2008. SFAS 157 defines fair value, establishes criteria to be considered when measuring fair value and expands disclosures about fair value measurements, but it does not expand the use of fair value accounting in any new circumstances. On February 12, 2008, the FASB issued FASB Staff Position No. FAS 157-2, *Effective Date of FASB Statement No. 157*, which amends SFAS 157 by allowing entities to delay its effective date by one year for non-financial assets and non-financial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis. We have deferred the application of SFAS 157 related to our asset retirement obligations until January 1, 2009, as permitted by this FSP. Adoption of SFAS 157 did not have a material impact on our financial position, results of operations or cash flows.

SFAS 157 establishes a fair value 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. The three broad levels include: quoted prices in active markets for identical assets or liabilities (Level 1); significant other observable inputs (Level 2); and significant unobservable inputs (Level 3).

Our assets and liabilities that are recorded at fair value on a recurring basis include cash equivalents and restricted cash consisting of money market funds, power-related derivatives and our Millstone decommissioning trust. Money market funds are classified as Level 1. Power-related derivatives are classified as Level 3. The Millstone decommissioning trust funds include treasury securities, other agency and corporate fixed income securities and equity securities that are classified as Level 2. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the SFAS 157 fair value hierarchy levels.

At December 31, 2008, the fair value of money market funds was $5 million and the fair value of decommissioning trust assets was $4.2 million. The fair value of power-related derivatives was a net unrealized gain of $8.8 million at December 31, 2008. This included unrealized gains of $12.9 million and unrealized losses of $4.1 million. See Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk for additional information about power-related derivatives.

Derivative Financial Instruments We account for various power contracts as derivatives under the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted and SFAS No. 149, *Amendment of Statement 133 Derivative Instruments and Hedging Activities*, (collectively "SFAS No. 133"). These statements require that derivatives be recorded on the balance sheet at fair value. We estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and market data and other assumptions. Fair value estimates involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future energy prices, including supply and demand levels and future price volatility. Based on a PSB-approved Accounting Order, we record the change in fair value of all power contract derivatives 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.

During 2008, we entered into several forward power contracts that we classify as derivatives. At December 31, 2008, the estimated fair value of all power contract derivatives was a net unrealized gain of $8.8 million ($12.9 million unrealized gain and $4.1 million unrealized loss). In 2007, we also had several forward power contracts that were derivatives. At December 31, 2007, the estimated fair value of all power contract derivatives was a net unrealized loss of $7.1 million ($7.8 million unrealized loss and $0.7 million unrealized gain). Also see Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk.

We are able to economically hedge our exposure to congestion charges that result from constraints on the transmission system with Financial Transmission Rights ("FTRs"). FTRs are awarded to the successful bidders in periodic auctions, in which we participate, that are administered by ISO-New England. We have determined that FTRs are derivatives. The estimated fair value of FTRs that we held at December 31, 2008 was $0.1 million and at December 31, 2007 was zero. We account for FTRs in the month they settle in ISO-New England; these are included in Purchased Power on the Consolidated Statements of Income. We believe that these assumptions are a reasonable approximation of our derivative values and the assumptions are reasonably likely to continue.

Environmental Reserves Environmental reserves are estimated and accrued using a probabilistic model when assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Our environmental reserve is for three sites in various stages of remediation. Our cost estimates for two of the sites are based on engineering evaluations of possible remediation scenarios and a Monte Carlo simulation. The cost estimate for the third site is less than $0.1 million. The liability estimate includes costs for remediation, monitoring and other future activities. At December 31, 2008, our reserve for the three sites was $1.7 million and it was $1.9 million at December 31, 2007. These estimates are based on currently available information from presently enacted state and federal environmental laws and regulations. The estimates are subject to revisions in future periods based on actual costs or new information concerning either the level of contamination at the site or newly enacted laws and regulations.

Reserve for Loss on Power Contract At December 31, 2008, we had a reserve of $8.4 million ($9.6 million at December 31, 2007) for loss on a terminated power contract resulting from the 2005 sale of a subsidiary's franchise. The loss represents our best estimate of the future sales revenue, in the wholesale market, and the cost of purchased power obligations. We base our calculation on assumptions about future power prices, the reallocation of power from the state-appointed purchasing agent and future load growth. We assess the carrying value of the liability, recorded to Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheet, regularly and continue to amortize the amount reserved on a straight-line basis. We believe that these assumptions are a reasonable approximation of our reserve for loss on power contract and the assumptions are reasonably likely to continue.

Income Taxes We adopted FIN 48 on January 1, 2007 as required. It did not have a material impact on our results of operations or statement of financial position. FIN 48 clarifies the methodology to be used in estimating and reporting amounts associated with uncertain tax positions, including interest and penalties. The application of income tax law is complex and we are required to make many subjective assumptions and judgments regarding our income tax exposures. Changes in our subjective assumptions and judgments can materially affect amounts recognized on the income statement, balance sheet and statement of cash flows.

Other See Part II, Item 8, Note 1 - Business Organization and Summary of Significant Accounting Policies for a discussion of newly adopted accounting policies and recently issued accounting pronouncements.

RESULTS OF OPERATIONS

The following is a detailed discussion of the results of operations for the past three years. This should be read in conjunction with the consolidated financial statements and accompanying notes included in this report.

Consolidated Summary Consolidated net income for the past three years follows (dollars in thousands, except earnings per share):

	2008	2007	2006
Income from continuing operations	**$ 16,385**	$ 15,804	$ 18,101
Income from discontinued operations	**0**	0	251
Net Income	**$ 16,385**	$ 15,804	$ 18,352
Earnings per share - basic:			
Earnings from continuing operations	**$ 1.53**	$ 1.52	$ 1.65
Earnings from discontinued operations	**0**	0	0.02
Earnings per share	**$ 1.53**	$ 1.52	$ 1.67
Earnings per share - diluted:			
Earnings from continuing operations	**$ 1.52**	$ 1.49	$ 1.64
Earnings from discontinued operations	**0**	0	0.02
Earnings per share	**$ 1.52**	$ 1.49	$ 1.66

The tables that follow provide a reconciliation of the primary year-over-year variances in diluted earnings per share for 2008 versus 2007 and 2007 versus 2006. The earnings per diluted share for each variance shown below are non-GAAP measures:

	2008 vs. 2007
2007 Earnings per diluted share	**$ 1.49**
Year-over-Year Effects on Earnings:	
Higher operating revenues	0.73
Higher equity in earnings of affiliates	0.54
Higher purchased power expense	(0.27)
Higher transmission expense	(0.25)
Higher interest expense	(0.17)
Higher other operating expenses	(0.21)
Other	(0.34)
2008 Earnings per diluted share	**$ 1.52**

	2007 vs. 2006
2006 Earnings per diluted share	**$ 1.66**
Year-over-Year Effects on Earnings (a):	
Higher operating revenues	0.15
Higher equity in earnings of affiliates	0.19
Lower purchased power expense	0.49
Higher transmission expense	(0.37)
Higher other operating expenses	(0.42)
Other	(0.21)
2007 Earnings per diluted share	**$ 1.49**

(a) The favorable impact of the April 2006 stock buyback is included in the individual EPS variances and not shown separately in the table above.

Consolidated Income Statement Discussion The following includes a more detailed discussion of the components of our Consolidated Statements of Income and related year-over-year variances.

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 contract price of those sales. Operating revenues and related mWh sales are summarized below.

	Revenue (dollars in thousands)			**mWh Sales**		
	2008	**2007**	**2006**	**2008**	**2007**	**2006**
Residential	**$ 138,091**	$ 136,359	$ 124,520	**982,966**	1,003,055	959,455
Commercial	**108,252**	107,556	103,432	**873,192**	885,713	888,537
Industrial	**34,858**	36,064	35,052	**396,741**	425,356	430,348
Other	**1,872**	1,840	1,768	**6,312**	6,250	6,125
Total Retail	**283,073**	281,819	264,772	**2,259,211**	2,320,374	2,284,465
Resale Sales	**48,641**	38,935	53,149	**759,832**	697,749	1,031,171
Provision for Rate Refund	**(296)**	(747)	0	**0**	0	0
Other Operating Revenues	**10,744**	9,100	7,817	**0**	0	0
Operating Revenues	**$ 342,162**	$ 329,107	$ 325,738	**3,019,043**	3,018,123	3,315,636

The average number of retail customers is summarized below:

	2008	**2007**	**2006**
Residential	**136,074**	135,591	131,483
Commercial	**22,407**	22,106	21,506
Industrial	**35**	37	35
Other	**175**	175	173
Total	**158,691**	157,909	153,197

Comparative changes in operating revenues are summarized below (dollars in thousands):

	2008 vs. 2007	2007 vs. 2006
Retail sales:		
Volume (mWh)	**$ (6,660)**	$ 4,960
Average price due to customer sales mix	**2,194**	1,124
Average price due to rate increases Jan. 2007 and Feb. 2008	**5,720**	10,963
Subtotal	**1,254**	17,047
Resale sales	**9,706**	(14,214)
Provision for rate refund	**451**	(747)
Other operating revenues	**1,644**	1,283
Increase in operating revenues	**$ 13,055**	$ 3,369

<u>2008 vs. 2007</u>

Operating revenues increased $13.1 million, or 3.97 percent, due to the following factors:

- Retail sales increased $1.3 million resulting from a 2.3 percent rate increase effective February 1, 2008 and a higher average price due to customer sales mix. Retail sales volume was lower in 2008 largely due to lower average usage caused by milder weather, a slowing economy and energy conservation.
- Resale sales increased $9.7 million resulting from higher average prices and an increase in excess power available for resale due to lower retail sales volume, higher output from our hydro facilities and Independent Power Producers and less lost output from unplanned outages at Vermont Yankee.
- The provision for rate refund, which is a reduction in operating revenues, is related to amounts that were included in retail rates in 2007 and January 2008 that were to be refunded to customers. The provision for refund ended with new retail rates effective February 1, 2008 that reflect the customer refund.
- Other operating revenues increased $1.6 million due to sales of transmission rights and increased revenue from storm restoration performed for other utilities, partially offset by a provision for refund to retail customers.

2007 vs. 2006

Operating revenues increased $3.4 million, or 1 percent, due to the following factors:

- Retail sales increased $17 million resulting from a 4.07 percent rate increase as of January 1, 2007 and higher residential sales volume. Retail sales volume increased during 2007 largely due to an increase in the number of residential customers resulting from small service territory acquisitions in the second half of 2006 and customer growth in our service territory. Colder weather in the winter months in 2007 also contributed to increased retail sales volume. Customer sales mix increased average prices on retail sales because the unit price for residential sales is higher than those of other customer classes.
- Resale sales decreased $14.2 million resulting from less excess power available for resale. The decrease in excess power available for resale resulted from second quarter 2007 scheduled refueling outages at Vermont Yankee and Millstone Unit #3, decreased Vermont Yankee purchases due to a derate and unplanned outage during the third quarter of 2007, and lower output from our hydro facilities and from Independent Power Producers due to less rainfall compared to 2006. The increase in retail sales volume also reduced the amount of power available for resale. Additionally, 2006 results included approximately $8.4 million of Vermont Yankee uprate energy that was resold as described in Purchased Power below. This power was resold at the same prices that we paid for it.
- The provision for rate refund decreased revenue by $0.7 million. This amount was included in the 4.07 percent rate increase and was refunded to customers in 2008 because the PSB disallowed our request to recover $1.5 million of Vermont Yankee 2005 incremental refueling costs over two years.
- Other operating revenues increased $1.3 million largely from the sale of additional transmission capacity on our share of Phase I/II transmission facility rights, offset by revenue for storm restoration performed for other utilities in 2006.

Operating Expenses The variances in income statement line items that comprise operating expenses on the Consolidated Statements of Income are described below (dollars in thousands).

	2008 over/(under) 2007		**2007 over/(under) 2006**	
	Total Variance	**Percent**	**Total Variance**	**Percent**
Purchased power - affiliates and other	**$ 4,729**	**2.9%**	$ (8,726)	5.1%
Production	**523**	**4.5%**	1,972	20.3%
Transmission - affiliates	**2,136**	**41.5%**	3,970	*
Transmission - other	**2,327**	**14.1%**	2,605	18.7%
Other operation	**2,287**	**4.3%**	4,775	9.8%
Maintenance	**55**	**0.2%**	5,898	26.8%
Depreciation	**443**	**2.9%**	(1,281)	-7.8%
Taxes other than income	**513**	**3.4%**	782	5.4%
Income tax expense (benefit)	**(413)**	**-7.8%**	(3,278)	-38.3%
Total operating expenses	**$ 12,600**	**4.0%**	$ 6,717	2.2%

* variance exceeds 100 percent

Purchased Power - affiliates and other: Power purchases made up 51 percent of total operating expenses in 2008, 52 percent in 2007 and 56 percent in 2006. Most of these purchases are made under long-term contracts. These contracts and other power supply matters are discussed in more detail in Power Supply Matters below. Purchased power expense and volume are summarized below:

	Purchases (in thousands)			**mWh purchases**		
	2008	2007	2006	**2008**	2007	2006
VYNPC (a)	**$ 57,708**	$ 55,772	$ 70,116	**1,417,144**	1,361,754	1,689,390
Hydro-Quebec	**63,670**	64,869	64,297	**937,923**	998,411	998,365
Independent Power Producers	**26,430**	22,796	23,998	**202,193**	176,169	198,735
Subtotal long-term contracts	**147,808**	143,437	158,411	**2,557,260**	2,536,334	2,886,490
Other purchases	**16,877**	16,018	5,525	**165,362**	219,186	90,440
SFAS No. 5 Loss amortizations	**(1,196)**	(1,196)	(1,196)	**0**	0	0
Nuclear decommissioning	**2,070**	2,588	5,412	**0**	0	0
Other	**(108)**	(125)	1,296	**0**	0	0
Total purchased power	**$ 165,451**	$ 160,722	$ 169,448	**2,722,622**	2,755,520	2,976,930

(a) Regulatory deferrals of $0.5 million in 2007 and 2008 have been reclassified and included in Other to conform to current year presentation.

Comparative changes in purchased power expense are summarized below (dollars in thousands):

	2008 vs. 2007	2007 vs. 2006
VYNPC (a)	**$ 1,936**	$ (14,344)
Hydro-Quebec	**$ (1,199)**	$ 572
Independent Power Producers	**$ 3,634**	$ (1,202)
Subtotal long-term contracts	**$ 4,371**	$ (14,974)
Other purchases	**$ 859**	$ 10,493
Nuclear decommissioning	**$ (518)**	$ (2,824)
Other	**$ 17**	$ (1,421)
Total purchased power	**$ 4,729**	$ (8,726)

2008 vs. 2007

Purchased power expense increased $4.7 million, or 2.9 percent, due to the following factors:

- Purchased power costs under long-term contracts increased $4.4 million in 2008, due primarily to increased purchases from Independent Power Producers at higher prices and from increased Vermont Yankee plant output we purchase at favorable rates under the long-term power contract ("PPA") with Vermont Yankee Nuclear Power Corporation ("VYNPC"). The Vermont Yankee plant operated at nearly full capacity in 2008 with the exception of a few small derates and the planned refueling outage in the fourth quarter. These increases were offset by fewer purchases from Hydro-Quebec due to a 5 percent decrease in the annual load factor.
- Other purchases increased $0.9 million in 2008 resulting from higher average prices for replacement energy purchased during the Vermont Yankee refueling outage and derate described above.
- Nuclear decommissioning costs decreased $0.5 million in 2008 and are associated with our ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. These costs are based on FERC-approved tariffs. The decrease is largely due to lower revenue requirements for Connecticut Yankee and Maine Yankee.

2007 vs. 2006

Purchased power expense decreased $8.7 million, or 5.1 percent, due to the following factors:

- Purchased power costs under long-term contracts decreased $15 million in 2007 largely resulting from decreased Vermont Yankee plant output we purchase under the PPA with VYNPC. The Vermont Yankee plant produced less power in 2007 due to a second-quarter scheduled refueling outage and a third-quarter derate and unplanned outage. Also in 2006 we were required to purchase additional Vermont Yankee uprate power at market prices. That power was resold in the wholesale energy markets as described in Revenue above. Purchases from Independent Power Producers, most of which are hydro facilities, decreased resulting from less rainfall, partly offset by an increase in average rates. Purchases from Hydro-Quebec increased during 2007 resulting from an increase in the average energy price.
- Other purchases increased $10.5 million in 2007 resulting from replacement energy purchased during the Vermont Yankee outages and derate described above.
- Nuclear decommissioning costs are associated with our ownership interests in the Maine Yankee, Connecticut Yankee and Yankee Atomic plants. These costs decreased $2.8 million in 2007 due to lower collection schedules for Connecticut Yankee and Yankee Atomic. Decommissioning activities were completed at both plants during 2007. Maine Yankee decommissioning activity was completed in 2006.
- Other costs decreased $1.4 million principally due to a net accounting deferral in 2007 versus amortizations in 2006 for Millstone Unit #3 scheduled refueling outages. Based on approved regulatory accounting treatment, we defer the cost of incremental replacement energy costs of scheduled refueling outages, and amortize those costs through the next scheduled refueling outage, which typically spans an 18-month period. The last refueling outage at Millstone Unit #3 occurred in April and May 2007.

Production: These costs represent the cost of fuel, operation and maintenance, property insurance, and property tax for our wholly and jointly owned production units. There was no significant variance for 2008 versus 2007.

The increase of $2 million for 2007 versus 2006 resulted primarily from premium expense of $1.3 million for Vermont Yankee outage insurance. This amount was amortized over 12 months beginning January 1, 2007. Fuel costs also increased $0.5 million.

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 NEPOOL Open Access Transmission Tariff ("NOATT") reimbursements and certain direct charges. The NOATT is the mechanism through which the costs of New England's high-voltage (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 increase of $2.1 million for 2008 versus 2007 is principally due to higher rates under the VTA, related to the overall transmission expansion in New England, partially offset by higher NOATT reimbursements.

The increase of $4 million for 2007 versus 2006 is principally due to higher rates, and lower reimbursements under NOATT. In 2006 transmission expenses from Transco decreased $1.5 million. This decrease was primarily due to third quarter 2006 NOATT reimbursements to Transco that were higher than Transco's cost of service, partly due to the inclusion of the Northwest Reliability Project in reimbursements. Our share amounted to a $2 million reimbursement, which was recorded as a reduction in transmission expense for the third quarter of 2006.

Transmission - other: The majority of these expenses are for purchases of regional transmission service under the NOATT and charges for the Phase I and II transmission facilities. The increase of $2.3 million for 2008 versus 2007 primarily resulted from higher rates and overall transmission expansion in New England.

The increase of $2.6 million for 2007 versus 2006 primarily resulted from higher rates, partially offset by lower depreciation expense because the Phase I facility was fully depreciated in 2006.

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 increase of $2.3 million for 2008 versus 2007 was primarily related to higher employee-related costs, higher net regulatory amortizations and higher reserves for uncollectible accounts, partially offset by lower professional service costs.

The increase of $4.8 million for 2007 versus 2006 resulted from: 1) a third-quarter 2006 reduction in environmental reserves based on revised cost estimates; 2) higher bad debt expense related to a customer bankruptcy and, in 2006, recovery of a previous charge-off; and 3) higher other costs, including professional services. These were partially offset by lower pension and postretirement medical costs primarily due to additional contributions to the trust funds in March 2006, and lower external audit fees.

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 $0.1 million for 2008 versus 2007 was largely due to increased storm recovery activity, net of a favorable deferral of $4.1 million of service restoration costs resulting from the ice storm in December 2008. The cost of this storm, the most expensive storm in the company's history, exceeded $5 million. The so-called Nor'icane in April 2007, previously our most costly storm, resulted in incremental service restoration costs of $3.5 million. The increase of $5.9 million for 2007 versus 2006 was primarily related to storm restoration costs from the storm in April 2007 and storms in August 2007.

Depreciation: We use the straight-line remaining-life method of depreciation. There was no significant variance for 2008 versus 2007. The $1.3 million decrease for 2007 versus 2006 was due to lower rates resulting from a depreciation study, and the license extension of our jointly owned nuclear plant, Millstone Unit #3.

Taxes other than income: This is related primarily to property taxes and payroll taxes. There was no significant variance for 2008 versus 2007 or for 2007 versus 2006.

Income tax expense (benefit): Federal and state income taxes fluctuate with the level of pre-tax earnings in relation to permanent differences, tax credits, tax settlements and changes in valuation allowances for the periods. The effective combined federal and state income tax rate was 39.6 percent for 2008, 29.9 percent for 2007 and 35.6 percent for 2006. Also see Part II, Item 8, Note 16 - Income Taxes.

Other Income and Other Deductions These items are related to the non-operating activities of our utility business and the operating and non-operating activities of our non-regulated businesses through CRC. CRC's earnings were $0.2 million in 2008, $0.5 million in 2007 and $0.8 million in 2006. The variances in income statement line items that comprise other income and other deductions on the Consolidated Statements of Income are shown in the table below (dollars in thousands).

	2008 over/(under) 2007		2007 over/(under) 2006	
	Total Variance	**Percent**	Total Variance	Percent
Equity in earnings of affiliates	**9,834**	*****	$ 3,190	98.5%
Allowance for equity funds during construction	**281**	*****	(73)	-60.8%
Other income	**(215)**	**-5.6%**	(1,674)	-30.5%
Other deductions	**2,324**	**93.7%**	80	3.3%
Income tax expense	**4,404**	*****	21	1.5%
Total other income and deductions	**3,172**	**49.9%**	$ 1,342	26.8%

* variance exceeds 100 percent

Equity in earnings of affiliates: These earnings are related to our equity investments including VELCO, Transco and VYNPC. The increase of $9.8 million for 2008 versus 2007 is principally from increased earnings resulting from an additional $53 million investment we made in Transco in December 2007. The $3.2 million increase for 2007 versus 2006 also resulted principally from our 2006 investment in Transco of $23.3 million.

Other income: These items include interest and dividend income on temporary investments, non-utility revenues relating to rental water heaters, and miscellaneous other income. There were no significant variances for 2008 versus 2007.

The decrease of $1.7 million for 2007 versus 2006 resulted primarily from a $1.3 million decrease in interest on temporary investments due to a lower portfolio balance resulting from the stock buyback in 2006, and a $0.3 million gain on the sale of non-utility property in 2006.

Other Deductions: These items include supplemental retirement benefits and insurance, including changes in the cash surrender value of life insurance policies, non-utility expenses relating to rental water heaters, and miscellaneous other deductions. The increase of $2.3 million for 2008 versus 2007 resulted primarily from market losses on the cash surrender value of life insurance policies included in our Rabbi Trust. There were no significant variances for 2007 versus 2006.

Benefit (expense) for income taxes: 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 variance of $4.4 million for 2008 versus 2007 is principally due to increased equity in earnings from our investment in Transco.

Interest Expense Interest expense includes interest on long-term debt, dividends associated with preferred stock subject to mandatory redemption, interest on notes payable and the credit facility, and carrying charges associated with regulatory liabilities. The variances in income statement line items that comprise interest expense on the Consolidated Statements of Income are shown in the table below (dollars in thousands).

	2008 over/(under) 2007		2007 over/(under) 2006	
	Total Variance	**Percent**	Total Variance	Percent
Interest on long-term debt	**2,581**	**35.9%**	$ 1	0.0%
Other interest	**565**	**42.0%**	270	25.1%
Allowance for borrowed funds during construction	**(100)**	***%**	20	-51.3%
Total interest expense	**3,046**	**35.7%**	$ 291	3.5%

Interest on long-term debt: The increase of $2.6 million for 2008 versus 2007 was largely due to the $60 million first mortgage bonds issued in May 2008. There were no significant variances for 2007 versus 2006.

Other interest expense: The increase of $0.6 million for 2008 versus 2007 was principally related to a bridge loan that was repaid in May 2008 from proceeds of a long-term debt issue, partially offset by lower regulatory carrying costs. The increase of $0.3 million for 2007 versus 2006 was principally due to regulatory carrying costs associated with an environmental reserve.

POWER SUPPLY MATTERS

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

Our current power forecast shows energy purchase and production amounts in excess of load obligations through 2011. Due to the forecasted excess, we enter into fixed-price forward sale transactions to reduce price (revenue) volatility in order to help stabilize our net power costs. We have entered into several forward sale contracts since January 1, 2008. The contracts vary from one to 12 months with volumes from 2 MW to 60 MW depending upon our forecast energy excesses in the on-peak and off-peak periods of each month. Some of the contracts are contingent on Vermont Yankee plant output, eliminating the risks related to sourcing the sale if Vermont Yankee is not operating. Others are firm sales, thus potentially exposing us to the risk of market price volatility if we are not able to source the contracts with existing resources. Our main supply risk is with Vermont Yankee, and we have outage insurance through March 31, 2009 to mitigate the market price risk during an unplanned outage through that time. We are currently working with an insurance broker to obtain insurance coverage for the remainder of 2009 through March 2012 when the contract between Entergy-Vermont Yankee and VYNPC ends.

A breakdown of energy sources during the past three years follows.

	2008	2007	2006
Nuclear	**50%**	48%	54%
Hydro	**39%**	39%	38%
Oil and wood	**5%**	6%	5%
Other	**6%**	7%	3%
Total	**100%**	100%	100%

The following is a discussion of our primary sources of energy.

Vermont Yankee: We are purchasing our entitlement share of Vermont Yankee plant output through the PPA between Entergy-Vermont Yankee and VYNPC. One remaining secondary purchaser continues to receive less than 0.5 percent of our entitlement. An uprate in 2006 increased the plant's operating capacity by approximately 20 percent. After completion of the uprate, VYNPC's entitlement to plant output declined from 100 percent to 83 percent, and our entitlement share declined from 35 percent to 29 percent. Therefore our nominal entitlement continues to be approximately 180 MW. Entergy-Vermont Yankee has no obligation to supply energy to VYNPC over its entitlement share of plant output, so we receive reduced amounts when the plant is operating at a reduced level, and no energy when the plant is not operating. The plant normally shuts down for about one month every 18 months for maintenance and to insert new fuel into the reactor. A scheduled refueling outage was completed in November 2008.

Prices under the PPA increase $1 per megawatt-hour each calendar year, from $42 in 2009 to $45 in 2012. The PPA contains a provision known as the "low market adjuster", which calls for a downward adjustment in the contract price if market prices for electricity fall by defined amounts; however, if market prices rise, PPA prices are not adjusted upward in excess of the PPA price. Estimated annual purchases are expected to range from $61 million to $64 million for 2009 through 2011, and $17 million for 2012 when the contract expires. The total cost estimates are based on projected mWh purchase volumes at PPA rates, plus estimates of VYNPC costs, which are primarily net interest expense and the cost of capital. Actual amounts may differ.

While the Vermont Yankee plant has a strong operating record, future unscheduled outages or reduced output could occur at times when replacement energy costs are above the PPA rates. We have forced outage insurance to cover additional costs, if any, of obtaining replacement power if the plant experiences unplanned outages. The coverage applies to unplanned outages of up to 30 consecutive calendar days per outage event, and provides for payment of the difference between the spot market price and approximately $40/mWh. The aggregate maximum coverage is $12 million. This outage insurance does not apply to derates. In the first quarter of 2008, we renegotiated the policy to extend coverage through March 31, 2009 instead of December 31, 2008. We are currently working with an insurance broker to obtain insurance coverage for the remainder of 2009 through March of 2012, when the contract ends.

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

If the Vermont Yankee plant is shut down for any reason prior to the end of its operating license, we would lose the economic benefit of an energy volume of close to 50 percent of our total committed supply and have to acquire replacement power resources for approximately 40 percent of our estimated power supply needs. Based on projected market prices as of December 31, 2008, the incremental replacement cost of lost power, including capacity, is estimated to average $37.5 million annually. 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 any such shutdown. An early shutdown could materially impact our financial position and future results of operations if the costs are not recovered in retail rates in a timely fashion. The Power Cost Adjustment Mechanism within our alternative regulation plan will allow more timely recovery of power costs for 2009, 2010 and 2011.

Hydro Quebec: We are purchasing power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract. The VJO is a group of Vermont electric companies, municipal utilities and cooperatives, including us. There are specific contractual provisions that provide that in the event any VJO member fails to meet its obligation under the contract, the remaining VJO participants will "step-up" to the defaulting party's share on a pro-rata basis. We are not aware of any instance where this provision has been invoked by Hydro-Quebec.

Based on sellback contracts that were negotiated in the early phase of the VJO Power Contract, Hydro-Quebec obtained two options. The first gives Hydro-Quebec the right, upon four years' written notice, to reduce capacity deliveries by 50 MW, including the use of a like amount of our Phase I/II transmission facility rights. The second gives Hydro-Quebec the right, upon one year's written notice, to curtail energy deliveries in a contract year (12 months beginning November 1) from an annual capacity factor of 75 to 50 percent due to adverse hydraulic conditions as measured at certain metering stations on unregulated rivers in Quebec. This second option can be exercised five times through October 2015. To date, Hydro-Quebec has not exercised these options.

Under the VJO Power Contract, the VJO and Hydro-Quebec had elections to change the annual load factor. Hydro-Quebec and the VJO have used all of their elections. Based on elections made by the VJO in 2006 and 2005, the load factor was at 80 percent for the contract years beginning November 1, 2006 and 2005. As of November 1, 2007, the annual load factor is 75 percent for the remainder of the contract, unless the contract is changed or there is a reduction due to the adverse hydraulic conditions described above. Estimated annual purchases are expected to range from $53.1 million to $67.6 million for 2009 through 2013. These estimates are based on certain assumptions including availability of the transmission system and scheduled deliveries, so actual amounts may differ.

Power Supply Request For Proposal ("RFP"): In November 2008, together with Green Mountain Power ("GMP") and Vermont Electric Cooperative ("VEC") we submitted a request for proposal ("RFP") to diversify our future power supplies and plan for the expiration of major contracts with Vermont Yankee and Hydro-Quebec between March 2012 and 2016. We issued two solicitations, the first of a series of several staggered RFPs that we plan to issue over the next couple of years.

In the first RFP, the Vermont utilities sought up to 100 megawatts of energy, including up to 40 megawatts each for us and GMP, and 20 megawatts for VEC. The second RFP, issued by us and GMP for 150 megawatts of new energy, is contingent on the outcome of Vermont Yankee relicensing and contract negotiations. The three Vermont utilities are in continuing negotiations with Hydro-Quebec and Vermont Yankee; therefore, those entities were not eligible to bid. Bids have been received from both RFPs and we expect to conclude negotiations and begin to execute purchased power agreements in April 2009.

The RFPs were distributed to all New England Power Pool participants, power suppliers and developers. Bidders from across the Northeast and Canada include powers marketers, energy developers, existing and to-be-built power plant owners and financial institutions. In total, bidders offered more than 1,800 megawatts providing a diversity of options.

The electric utilities plan to award and sign contracts based on the RFPs this spring, but we are unable to predict the outcome of this matter or the impact on our financial statements and cash flows.

Independent Power Producers: We purchase power from a number of Independent Power Producers that own qualifying facilities under the Public Utility Regulatory Policies Act of 1978. These qualifying facilities produce energy using hydroelectric and biomass generation. Most of the power comes through a state-appointed purchasing agent that allocates power to all Vermont utilities under PSB rules. Estimated annual purchases are expected to range from $17.7 million to $19.4 million for 2009 through 2012. These estimates are based on assumptions regarding average weather conditions and other factors affecting generating unit output, so actual amounts may differ.

Wholly owned hydro and thermal: Our wholly owned plants are located in Vermont, and have a combined nameplate capacity of about 74.2 MW. We operate all of these plants, which include: 1) 20 hydroelectric generating facilities with nameplate capacities ranging from a low of 0.3 MW to a high of 7.5 MW, for an aggregate nameplate capacity of 45.3 MW; 2) two oil-fired gas turbines with a combined nameplate capacity of 26.5 MW; and 3) one diesel peaking unit with a nameplate capacity of 2.4 MW, which is currently deactivated.

Jointly owned units: Our jointly owned units include: 1) a 1.7303 percent interest in Unit #3 of the Millstone Nuclear Power Station, a 1,155 MW nuclear generating facility; 2) a 20 percent interest in Joseph C. McNeil, a 54 MW wood-, gas- and oil-fired unit; and 3) a 1.7769 percent joint-ownership in Wyman #4, a 609 MW oil-fired unit. We account for these units on a proportionate consolidated basis using our ownership interest in each facility. Therefore, our share of the assets, liabilities and operating expenses of each facility are included in the corresponding accounts in our consolidated financial statements.

Dominion Nuclear Connecticut ("DNC") is the lead owner of Millstone Unit #3 with about 93.4707 percent of the plant joint-ownership. The plant's operating license has been extended from November 2025 to November 2045. We have an external trust dedicated to funding our share of future decommissioning costs, but we have suspended contributions to the Millstone Unit #3 Trust Fund because the minimum NRC funding requirements are being met or exceeded. If a need for additional decommissioning funding is necessary, we will be obligated to resume contributions to the Trust Fund.

In August 2008, the NRC approved a request by DNC to increase the Millstone Unit #3 plant's generating capacity by approximately 7 percent. We are obligated to pay our share of the related costs based on our ownership share described above. The uprate was completed during the scheduled refueling outage that concluded in November 2008 and our share of plant output increased by 1.4 MW.

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. 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.

Other: Other sources of energy are largely related to short-term purchases from third parties in New England and the wholesale markets in ISO-New England. On an hourly basis, power is sold or bought through ISO-New England to balance our resource output and load requirements through the normal settlement process. On a monthly basis, we aggregate hourly sales and purchases and record them as operating revenues and purchased power, respectively. We are also charged for a number of ancillary services through ISO-New England, including costs for congestion, line losses, reserves and regulation that vary in part due to changes in the price of energy. The method for settling the cost of congestion and other ancillary services is administered by ISO-New England and is subject to change. Congestion and loss charges represent the cost of delivering energy to customers and reflect energy prices, customer demand, and the demands on transmission and generation resources.

In December 2006, ISO-New England implemented a new market mechanism referred to as the Forward Capacity Market ("FCM") to compensate owners of new and existing generation capacity, including demand reduction. ISO-New England believes that higher capacity payments in constrained areas will encourage the development of new generation where needed. Capacity requirements for load-serving entities, including us, are based on each entity's proportionate share of ISO-New England's prior year coincident peak demand and the amount of qualifying capacity in the pool. Based on specified rates through May 2010, we expect net FCM charges of about $4 million in 2009.

We continue to monitor potential changes to the rules in the wholesale energy markets in New England. Such changes could have a material impact on power supply costs.

Decommissioned Nuclear Plants We own, through equity investments, 2 percent of Maine Yankee, 2 percent of Connecticut Yankee and 3.5 percent of Yankee Atomic. As of December 31, 2008, all three have completed decommissioning activities and their operating licenses have been amended to operation of Independent Spent Fuel Storage Installation. They remain separately responsible for safe storage of each plant's spent nuclear fuel and waste at the sites until the DOE meets its obligation to remove the material from the site or until some other suitable storage arrangement can be developed. All three collect decommissioning and closure costs through FERC-approved wholesale rates charged under power purchase agreements with several New England utilities, including us. We believe that, based on historical rate recovery, our share of decommissioning and closure costs for each plant will continue to be recovered through the regulatory process. However, if the FERC disallows recovery of any of their costs, there is a risk that the PSB would disallow recovery of our share in retail rates.

Based on estimates from Maine Yankee, Connecticut Yankee and Yankee Atomic as of December 31, 2008, the total remaining approximate cost for decommissioning and other costs of each plant is as follows: $67.3 million for Maine Yankee, $312.1 million for Connecticut Yankee and $70.5 million for Yankee Atomic. Our share of the remaining obligations amounts to $1.3 million for Maine Yankee, $6.2 million for Connecticut Yankee and $2.5 million for Yankee Atomic. These estimates may be revised from time to time based on information available regarding future costs.

On October 4, 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. The three companies had claimed actual damages through the same periods in the amounts of $78.1 million for Maine Yankee, $37.7 million for Connecticut Yankee and $60.8 million for Yankee Atomic. On December 4, 2006, the DOE filed a notice of appeal to the United States Court of Appeals for the Federal Circuit ("Appeals Court") in all three cases, and on December 14, 2006, all three companies filed notices of cross appeals.

On February 9, 2007, the Appeals Court issued an order consolidating the three cases. Later in 2007, the Appeals Court issued orders making two other cases companion appeals. Oral arguments on the pending appeals were held in February 2008. On August 7, 2008, the Appeals Court reversed the reward of damages and remanded the cases back to the trial courts. The remand directed the trial courts to apply the acceptance rate in the 1987 annual capacity reports when determining damages. On January 30, 2009, the Court of Federal Claims issued an order reserving weeks in August, 2009, for pre-trial conference, trial and any other proceedings necessary for final resolutions of the issues involved in the remanded cases. Due to the complexity of the issues and the potential for further appeals, the three companies cannot predict the amount of damages that will actually be received or the timing of the final determination of such damages. Each of the companies' respective FERC settlements require that damage payments, net of taxes and net of further spent fuel trust funding, be credited to ratepayers including us. We expect that our share of these payments, if any, would be credited to our ratepayers as well.

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

TRANSMISSION MATTERS

As a load-serving entity, we are required to share the costs related to the region's high-voltage transmission system through payments made under the NEPOOL Open Access Transmission Tariff ("NOATT"). Our allocation of NOATT costs, based on our percentage of network load, is a small fraction of New England's obligation. While this regional cost-sharing approach reduces our costs related to qualifying Vermont transmission upgrades, we pay a share of the costs for new and existing NOATT-qualifying facilities located elsewhere in New England.

There are a number of major transmission projects in Vermont being undertaken by Transco, some of which are already in service. Many of these projects, including most of the so-called Northwest Reliability Project, have been approved by NEPOOL for NOATT cost-sharing treatment. However, certain future Vermont transmission facilities may not qualify for such cost sharing, and those costs would be charged locally (within Vermont) rather than regionally. Our share of such costs will be determined by the classification of each project; some will be charged directly to specific utilities and some will be shared by all Vermont utilities.

Transco has been working with us on a project to solve load serving and reliability issues related to a 46-kV transmission line extending from Bennington to Brattleboro, Vt., which we refer to as the Southern Loop. It serves about 25 percent of our load. We initiated a public involvement process in late 2005 to gain input on how best to improve and ensure reliable electric service in southern Vermont. Based on input from this process, in the fourth quarter of 2006 we filed a petition with the PSB for approval to purchase and install two synchronous condensers along the Southern Loop. This project was approved by the PSB in April 2008. Work commenced in June 2008 and was completed in February 2009. The final costs are expected to be approximately $11 million. The condensers are rotating machines similar to motors used to control power flow on electric power transmission systems without burning fuel. The condensers will improve the reliability in the Stratton/Manchester area of the Southern Loop. VELCO also worked with us on a proposal to construct additional transmission lines in the area in order to improve reliability to the Brattleboro area of the Southern Loop. This includes the construction of a new line in the existing 345 kV corridor between Vermont Yankee in Vernon and our substation in Coolidge, and construction of a new substation in Newfane. The plan also included a new substation in Vernon and an expansion of the Coolidge Substation. These components are collectively known as the "Coolidge Connector." To address local reliability problems on our system, the PSB also approved, on February 12, 2009, a 345 kV loop between Newfane and the 345 kV Vernon-to-Cavendish line.

The Regional Transmission Organization ("RTO") for New England began operating on February 1, 2005 pursuant to FERC Order 2000. We are a participant in this organization, which provides high-voltage transmission service on so-called Pool Transmission Facilities ("PTF") on a non-discriminatory basis throughout New England. Currently, costs are allocated for Regional Network Service ("RNS") each month based on each participant's percentage of network load. All utilities pay the same rate for facilities put into service after 1996, while the rate paid by a utility for facilities already in service at the end of 1996 is based, in part, on the cost of that utility's local portion of the PTF system. As of March 2008, all users paid the same rate for all facilities.

Under the RTO, Highgate and related facilities owned by a number of Vermont utilities and Transco, are classified as the Highgate Transmission Facility with a five-year phase-in of RNS reimbursement treatment. At the end of the phase-in period, our net cost for Highgate will be based on our NEPOOL load ratio (about 2 percent) rather than our 46 percent ownership share of the facilities. Our share of reimbursements is expected to be about $1.8 million.

RECENT ENERGY POLICY INITIATIVES

In 2007, the Vermont Legislature passed Act 79, *An Act Relating to Establishing the Vermont Telecommunications Authority to Advance Broadband and Wireless Communications Infrastructure throughout the State.* This new law set a goal of providing statewide broadband coverage by the end of 2010. The PSB is now examining the use or role of the electric utilities to facilitate deployment of high-speed telecommunications infrastructure and services throughout the state. In addition, the Vermont Legislature is currently considering a bill to: 1) clarify rate and tariff policies for telecommunication equipment on utility transmission and generation facilities; 2) better coordinate utility and telecommunication planning for new construction of distribution facilities; and 3) establish a mechanism for expediting the installation of communications facilities within existing easements.

On February 28, 2008, the Vermont Legislature gave final approval to S. 209, "the Vermont Energy Efficiency and Affordability Act." The bill was signed into law by the governor in 2008. Provisions of the bill include, among other things:

- A requirement that, by 2013, new renewable resources must provide electricity equivalent to 5 percent of the state's total retail electricity sales in 2005. This is in addition to a previously existing requirement that such resources produce the electricity equivalent to the state's incremental sales growth after 2005.
- Expansion of the state's net metering law by increasing the size of qualifying facilities from a capacity of 15 kW to 250 kW, and by authorizing group net metering for customers within a single utility service area;
- A requirement that Vermont electric utilities install advanced smart metering equipment capable of sending two-way signals and sufficient to support advanced time-of-use pricing.
- An expansion of the state's energy efficiency programs from the existing focus on electricity use to include thermal uses such as oil, propane, natural gas and wood used to heat homes and businesses. Funding for these new programs comes from existing sources, along with expected revenues from the Regional Greenhouse Gas Initiative.

- A state goal for all energy sectors to produce, by the year 2025, 25 percent of the energy consumed within the state from renewable energy sources, particularly from Vermont's farms and forests.

Despite passage of this bill, the Legislature continues to examine a wide variety of potential measures intended to increase reliance on renewable energy.

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

The Vermont Legislature also continues to hold hearings regarding Vermont Yankee, and the potential relicensing of the plant beyond 2012. Legislators have indicated a strong preference for a new power supply contract between Entergy, the plant's owner, and Vermont utilities, including us, before voting on the issue. It is unclear whether or when such a contract might be reached, and we cannot predict the outcome at this time. By state law, the Vermont Legislature and the PSB must affirmatively approve continued operation of Vermont Yankee after its license expires in March 2012.

We may become subject to legislative and regulatory initiatives regarding greenhouse gas emissions. Vermont enacted legislation requiring the state to participate in the Regional Greenhouse Gas Initiative ("RGGI").RGGI is a mandatory, market-based program to reduce greenhouse gas emissions. The program is designed to cap and then reduce CO2 emmissions from the power sector 10 percent by 2018 for ten Northeastern and Mid-Atlantic states. To reach this goal, states sell emission allowances through auctions and invest proceeds in consumer benefits such as energy efficiency, renewable energy, and other clean energy technologies. The purpose of RGGI is to spur innovation in the clean energy economy and create "green jobs" in each state.

The PSB issued an order in July 2008 to implement the auction provisions of the RGGI program. In September 2008, Vermont auctioned more than 200,000 of the available CO2 allowances to qualified bidders. The state expects to raise more than $2 million in each of the next several years, which it expects to invest in energy efficiency, renewable energy technologies and other programs.

Out of our portfolio of power resources, only the Wyman oil-fired cycling unit, in which we have a 10.8 MW share, is subject to RGGI (because the State of Maine is also a RGGI participant). As such, the direct compliance cost impact on us is expected to be very limited.

Indirect effects are also anticipated. For example, we expect that as the number of allowances that are auctioned across the region are reduced in future years, the cost of compliance for the region's power plants that meet load at the margin will include the cost of RGGI compliance and these costs are highly likely to be reflected in the region's wholesale power prices. At times when we are a net seller, this is expected to add to wholesale power revenues. Conversely, when we are a net buyer this is expected to add to net power costs. Net power costs are recoverable in base rates and as a component of the power cost adjustment mechanism under our approved Alternative Regulation Plan.

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

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

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

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

RECENT ACCOUNTING PRONOUNCEMENTS

In November 2008, the SEC issued a proposed roadmap for the potential use of International Financial Reporting Standards ("IFRS") in the U.S. IFRS is a set of accounting standards developed by the International Accounting Standards Board ("IASB"), whose mission is to develop a single set of global financial reporting standards for general purpose financial statements. The roadmap indicates that the SEC will reconvene in 2011 to evaluate progress towards certain identified milestones and decide whether a mandatory IFRS conversion should be required for all U.S. issuers beginning with large accelerated filers in 2014.

In December 2008, the IASB added to its agenda a project on rate-regulated activities. The issue is whether entities with such activities could or should recognize an asset or liability as a result of rate regulation imposed by regulatory bodies or governments. We currently recognize regulatory assets and liabilities under SFAS No. 71 as described above, which is not currently provided for under IFRS. We have not yet evaluated the potential impact that the application of IFRS may have on our financial statements, and we are unable to predict the outcome of this matter at this time.

Also, see Part II, Item 8, Note 1 - Business Organization and Summary of Significant Accounting Policies to the accompanying Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The matters discussed in this item may contain forward-looking statements as described in our "Cautionary Statement Regarding Forward-Looking Information" section preceding Part I, Item 1, Business of this Form 10-K. Also see Part I, Item 1A, Risk Factors.

We consider our most significant market-related risks to be associated with wholesale power markets, equity markets and interest rates. 2008 was a challenging year in the financial markets with record low market returns and extraordinary volatility. Further decreases in the values of the assets in our pension, postretirement medical and nuclear decommissioning trust funds could increase our future cash outflows related to trust fund contributions. Fair and adequate rate relief through cost-based rate regulation can limit our exposure to market volatility. Below is a discussion of the primary market-related risks associated with our business.

Wholesale Power Market Price Risk Our most significant power supply contracts are with Hydro-Quebec and VYNPC. Combined, these contracts amounted to between 70 to 80 percent of our total energy (mWh) purchases in 2008, 2007 and 2006. The contracts are described in more detail in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Power Supply Matters and Part II, Item 8, Note 17 - Commitments and Contingencies. Summarized information regarding power purchases under these contracts follows.

		2008			2007			2006		
	Expires	**mWh**		**$/mWh**	mWh		$/mWh	mWh		$/mWh
Hydro-Quebec (a)	2016	937,923	$	67.88	998,411	$	64.97	998,365	$	64.40
VYNPC (b)	March 2012	1,417,144	$	40.72	1,361,754	$	40.96	1,689,390	$	41.50

(a) Under the terms of the Hydro-Quebec contract, there is a defined energy rate that escalates at the general inflation rate based on the U.S. Gross National Product Implicit Price Deflator ("GNPIPD") and capacity rates are constant with the potential for small reductions if interest rates decrease below average values set in prior years.

(b) Under the terms of the contract with VYNPC the energy price generally ranges from 3.9 cents to 4.5 cents per kilowatt-hour through 2012. Effective November 2005, the contract prices are subject to a "low-market adjuster" mechanism.

Currently, our power forecast shows energy purchase and production amounts in excess of our load requirements through 2011. Because of this projected power surplus, we enter into forward sale transactions from time to time to reduce price volatility of our net power costs. The effect of increases or decreases in average wholesale power market prices is highly dependent on whether or not our net power resources at the time are sufficient to meet load requirements. If they are not sufficient to meet load requirements, such as when power from Vermont Yankee is not available as expected, we are in a purchase position. In that case, increased wholesale power market prices would increase our net power costs. If our net power resources are sufficient to meet load requirements, we are in a sale position. In that case, increased wholesale power market prices would decrease our net power costs. The Power Cost Adjustment Mechanism within our alternative regulation plan will allow more timely recovery of our power costs in 2009, 2010 and 2011.

We account for some of our power contracts as derivatives under the guidance of SFAS No. 133. These derivatives are described in Part II, Item 7, 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 Sales Contracts		**Forward Purchase Contracts**		**Hydro-Quebec Sellback #3**		**Total**
Total fair value at December 31, 2007 - unrealized loss	$	(2,037)	$	(481)	$	(4,592)	$	(7,110)
Plus new contracts entered into during the period		(440)		191		0		(249)
Less amounts settled during the period		7,385		1,165		0		8,550
Change in fair value during the period		7,845		(739)		523		7,629
Total fair value at December 31, 2008 - unrealized (loss) gain, net	$	12,753	$	136	$	(4,069)	$	8,820
Estimated fair value at December 31, 2008 for changes in projected market price:								
10 percent increase	$	9,652	$	150	$	(7,229)	$	2,573
10 percent decrease	$	15,857	$	122	$	(962)	$	15,017

Per a PSB-approved Accounting Order, changes in fair value of all power-related derivatives are recorded as deferred charges or deferred credits on the 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.

Investment Price Risk We are subject to investment price risk associated with equity market fluctuations and interest rate changes. Those risks are described in more detail below.

Interest Rate Risk: Interest rate changes could impact the value of the debt securities in our pension and postretirement medical trust funds and the calculations related to estimated pension and other benefit liabilities, affecting pension and other benefit expenses, contributions to the external trust funds and ultimately our ability to meet future pension and postretirement benefit obligations. We have adopted a diversified investment policy whose goal is to mitigate these market impacts. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Policies and Estimates, and Part II, Item 8, Note 15 - Pension and Postretirement Medical Benefits.

Interest rate changes could also impact the value of the debt securities in our Millstone Unit #3 decommissioning trust. At December 31, 2008, the trust held debt securities in the amount of $1.5 million.

As of December 31, 2008, we had $16.3 million of Industrial Development Revenue bonds outstanding, of which $10.8 million have an interest rate that floats monthly with the short-term credit markets and $5.5 million that floats every five years with comparable credit markets. All other utility debt has a fixed rate. There are no interest rate locks or swap agreements in place.

The table below provides information about interest rates on our long-term debt and Industrial Development Revenue bonds (dollars in millions).

	Expected Maturity Date						
	2009	2010	2011	2012	2013	Thereafter	Total
Fixed Rate ($)	**$ 11.00**	$ 10.80	$ 10.20	$ 9.80	$ 9.80	$ 112.10	$ 163.70
Average Fixed Interest Rate (%)	**6.36%**	6.44%	6.54%	6.64%	6.64%	6.98%	
Variable Rate ($)	**$ 0.10**	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.60
Average Variable Rate (%)	**0.92%**	0.92%	0.92%	0.92%	0.92%	1.00%	

Equity Market Risk: As of December 31, 2008, our pension trust held marketable equity securities in the amount of $34.5 million, our postretirement medical trust funds held marketable equity securities in the amount of $6.4 million, and our Millstone Unit #3 decommissioning trust held marketable equity securities of $2.7 million. We also maintain a variety of insurance policies in a Rabbi Trust with a current value of $5.5 million to support various supplemental retirement and deferred compensation plans. The current values of certain policies are affected by changes in the equity market.

Item 8. Financial Statements and Supplementary Data.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Central Vermont Public Service Corporation

We have audited the accompanying consolidated balance sheets of Central Vermont Public Service Corporation and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, comprehensive income, changes in common stock equity, and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the financial statement schedule listed in the Index at Item 15. These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits. We did not audit the financial statements of Vermont Transco LLC ("Transco") and Vermont Electric Power Company, Inc. ("Velco"), the Company's investments in which are accounted for by use of the equity method. The Company's equity of $99,121,000 and $90,318,000 in Transco's and Velco's net assets as of December 31, 2008 and 2007, respectively, and of $16,102,000 and $5,886,000 in Transco's and Velco's net income for the years ended December 31, 2008 and 2007, respectively, are included in the accompanying consolidated financial statements. Those financial statements were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Transco and Velco, is based solely on the reports of other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the reports of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of other auditors, such consolidated financial statements present fairly, in all material respects, the financial position of Central Vermont Public Service Corporation and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board ("FASB") Interpretation 48, *Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109*, effective January 1, 2007.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 11, 2009 expresses an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Boston, Massachusetts

March 11, 2009

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

	For the year ended December 31		
	2008	2007	2006
Operating Revenues	**$ 342,162**	$ 329,107	$ 325,738
Operating Expenses			
Purchased Power - affiliates	**59,778**	58,361	75,527
Purchased Power - other	**105,673**	102,361	93,921
Production	**12,223**	11,700	9,728
Transmission - affiliates	**7,280**	5,144	1,174
Transmission - other	**18,851**	16,524	13,919
Other operation	**55,744**	53,457	48,682
Maintenance	**27,992**	27,937	22,039
Depreciation	**15,660**	15,217	16,498
Taxes other than income	**15,653**	15,140	14,358
Income tax expense	**4,878**	5,291	8,569
Total Operating Expenses	**323,732**	311,132	304,415
Utility Operating Income	**18,430**	17,975	21,323
Other Income			
Equity in earnings of affiliates	**16,264**	6,430	3,240
Allowance for equity funds during construction	**328**	47	120
Other income	**3,598**	3,813	5,487
Other deductions	**(4,805)**	(2,481)	(2,401)
Income tax expense	**(5,862)**	(1,458)	(1,437)
Total Other Income	**9,523**	6,351	5,009
Interest Expense			
Interest on long-term debt	**9,778**	7,197	7,196
Other interest	**1,909**	1,344	1,074
Allowance for borrowed funds during construction	**(119)**	(19)	(39)
Total Interest Expense	**11,568**	8,522	8,231
Income from continuing operations	**16,385**	15,804	18,101
Income from discontinued operations, net of income taxes	**0**	0	251
Net Income	**16,385**	15,804	18,352
Dividends declared on preferred stock	**368**	368	368
Earnings available for common stock	**$ 16,017**	$ 15,436	$ 17,984
Basic earnings from continuing operations	**$ 1.53**	$ 1.52	$ 1.65
Basic earnings from discontinued operations	**$ 0.00**	$ 0.00	$ 0.02
Basic Earnings per share	**$ 1.53**	$ 1.52	$ 1.67
Diluted earnings from continuing operations	**$ 1.52**	$ 1.49	$ 1.64
Diluted earnings from discontinued operations	**$ 0.00**	$ 0.00	$ 0.02
Diluted earnings per share	**$ 1.52**	$ 1.49	$ 1.66
Average shares of common stock outstanding - basic	**10,458,220**	10,185,930	10,756,027
Average shares of common stock outstanding - diluted	**10,536,131**	10,350,191	10,827,182
Dividends declared per share of common stock	**$ 0.92**	$ 0.92	$ 0.69

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

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

	2008	2007	2006
Net Income	**$ 16,385**	$ 15,804	$ 18,352
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 $1 in 2008, $12 in 2007 and $0 in 2006	**2**	19	0
Prior service cost, net of income taxes of $9 in 2008 and 2007 and $0 in 2006	**13**	13	0
Transition benefit obligation, net of income taxes of $0 in 2008, 2007 and 2006	**1**	1	0
Portion reclassified due to adoption of SFAS 158 measurement provision, included in retained earnings			
Prior service cost, net of income taxes of $2 in 2008 and $0 in 2007 and 2006	**4**	0	0
Change in funded status of pension, postretirement medical and other benefit plans, net of income taxes of $89 in 2008, $92 in 2007 and $0 in 2006	**130**	133	0
Minimum pension liability adjustment, net of income taxes of $0 in 2008 and 2007 and $203 in 2006	**0**	0	285
Defined benefit pension plans, net	**150**	**166**	**285**
Investment securities:			
Unrealized holding gain, net of income taxes of $0 in 2008 and 2007 and $60 in 2006	**0**	0	89
Less reclassification adjustment for gains included in net income, net of income taxes of $0 in 2008 and 2007 and $(45) in 2006	**0**	0	(69)
Comprehensive income adjustments	**150**	**166**	**305**
Total comprehensive income	**$ 16,535**	$ 15,970	$ 18,657

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

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

(dollars in thousands)	For the Years Ended December 31		
Cash flows provided (used) by:	**2008**	2007	2006
OPERATING ACTIVITIES			
Net income	**$ 16,385**	$ 15,804	$ 18,352
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of affiliates	**(16,264)**	(6,430)	(3,240)
Distributions received from affiliates	**10,694**	4,894	2,106
Depreciation	**15,660**	15,217	16,498
Deferred income taxes and investment tax credits	**16,723**	2,726	3,820
Amortization of capital leases	**900**	873	1,096
Regulatory and other amortization, net	**(4,698)**	(5,097)	(3,354)
Non-cash employee benefit plan costs	**5,641**	6,794	9,997
Other non-cash expense and (income), net	**6,058**	3,979	413
Changes in assets and liabilities:			
Increase in accounts receivable and unbilled revenues	**(2,454)**	(366)	(5,456)
Decrease in accounts payable	**(1,740)**	(504)	(252)
(Decrease) increase in accounts payable – affiliates	**(1,867)**	1,183	620
Decrease (increase) in other current assets	**1,456**	614	(761)
(Increase) decrease in special deposits and restricted cash for power collateral	**(3,580)**	3,519	15,512
Employee benefit plan funding	**(7,880)**	(7,878)	(28,420)
Decrease in other current liabilities	**(5,222)**	(2,362)	(1,144)
(Increase) decrease in other long-term assets	**(2,178)**	40	(169)
Increase in other long-term liabilities and other	**766**	1,086	551
Net cash provided by operating activities of continuing operations	**28,400**	34,092	26,169
INVESTING ACTIVITIES			
Construction and plant expenditures	**(36,835)**	(23,663)	(19,504)
Investments in available-for-sale securities	**(1,475)**	(20,797)	(256,431)
Proceeds from sale of available-for-sale securities	**1,201**	20,670	334,390
Investment in affiliates (Transco)	**(3,090)**	(53,000)	(23,291)
Acquisition of utility property (Rochester Electric and Vermont Electric Coop)	**0**	0	(4,306)
Other investing activities	**(299)**	170	1,242
Net cash (used for) provided by investing activities of continuing operations	**(40,498)**	(76,620)	32,100
FINANCING ACTIVITIES			
Proceeds from issuance of common stock	**23,540**	2,131	1,267
Treasury stock acquisition - tender offer	**0**	0	(51,186)
Retirement of preferred stock subject to mandatory redemption	**(1,000)**	(1,000)	(2,000)
Common and preferred dividends paid	**(9,868)**	(9,734)	(10,164)
Proceeds from issuance of first mortgage bonds	**60,000**	0	0
Repayment of first mortgage bonds	**(3,000)**	0	0
(Repayment of) proceeds from short-term bridge loan	**(53,000)**	53,000	0
Proceeds from other short-term borrowings	**12,700**	45,600	18,100
Repayments under other short-term borrowings	**(12,700)**	(45,600)	(18,100)
Payments required for unremarketed bonds	**(3,400)**	0	0
Proceeds from remarketed bonds	**3,400**	0	0
Debt issuance and common stock offering costs	**(1,054)**	0	0
Other financing activities	**(601)**	(865)	37
Net cash provided by (used for) financing activities of continuing operations	**15,017**	43,532	(62,046)
Net increase (decrease) in cash and cash equivalents	**2,919**	1,004	(3,777)
Cash and cash equivalents at beginning of the period	**3,803**	2,799	6,576
Cash and cash equivalents at end of the period	**$ 6,722**	$ 3,803	$ 2,799

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

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

	December 31, 2008	December 31, 2007
ASSETS		
Utility plant		
Utility plant, at original cost	$ 554,506	$ 538,229
Less accumulated depreciation	244,219	235,465
Utility plant, at original cost, net of accumulated depreciation	310,287	302,764
Property under capital leases, net	6,133	6,788
Construction work-in-progress	24,632	9,611
Nuclear fuel, net	1,475	1,105
Total utility plant, net	342,527	320,268
Investments and other assets		
Investments in affiliates	102,232	93,452
Non-utility property, less accumulated depreciation ($3,657 in 2008 and $3,681 in 2007)	1,786	1,646
Millstone decommissioning trust fund	4,203	5,645
Other	5,469	7,504
Total investments and other assets	113,690	108,247
Current assets		
Cash and cash equivalents	6,722	3,803
Restricted cash	3,636	62
Special deposits	1,006	1,000
Accounts receivable, less allowance for uncollectible accounts ($2,184 in 2008 and $1,751 in 2007)	23,176	24,086
Accounts receivable - affiliates, less allowance for uncollectible accounts ($0 in 2008 and $48 in 2007)	76	254
Unbilled revenues	18,546	17,665
Materials and supplies, at average cost	6,299	5,461
Prepayments	17,367	8,942
Deferred income taxes	0	3,638
Power-related derivatives	12,758	707
Other current assets	1,269	1,081
Total current assets	90,855	66,699
Deferred charges and other assets		
Regulatory assets	63,474	31,988
Other deferred charges - regulatory	9,980	8,988
Other deferred charges and other assets	5,467	4,124
Power-related derivatives	133	0
Total deferred charges and other assets	79,054	45,100
TOTAL ASSETS	$ 626,126	$ 540,314

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

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

	December 31, 2008	December 31, 2007
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common stock, $6 par value, 19,000,000 shares authorized, 13,750,717 issued and 11,574,825 outstanding at December 31, 2008 and 12,474,687 issued and 10,244,559 outstanding at December 31, 2007	$ 82,504	$ 74,848
Other paid-in capital	71,489	56,324
Accumulated other comprehensive loss	(228)	(378)
Treasury stock, at cost, 2,175,892 shares at December 31, 2008 and 2,230,128 shares at December 31, 2007	(49,501)	(50,734)
Retained earnings	115,215	108,747
Total common stock equity	219,479	188,807
Preferred and preference stock not subject to mandatory redemption	8,054	8,054
Preferred stock subject to mandatory redemption	1,000	2,000
Long-term debt	167,500	112,950
Capital lease obligations	5,173	5,889
Total capitalization	401,206	317,700
Current liabilities		
Current portion of preferred stock subject to mandatory redemption	1,000	1,000
Current portion of long-term debt	5,450	3,000
Accounts payable	3,549	6,253
Accounts payable - affiliates	11,338	13,205
Notes payable	10,800	63,800
Nuclear decommissioning costs	1,431	2,309
Power-related derivatives	2	3,225
Other current liabilities	33,645	20,761
Total current liabilities	67,215	113,553
Deferred credits and other liabilities		
Deferred income taxes	45,314	33,666
Deferred investment tax credits	2,962	3,341
Nuclear decommissioning costs	8,618	9,580
Asset retirement obligations	3,302	3,200
Accrued pension and benefit obligations	51,211	19,874
Power-related derivatives	4,069	4,592
Other deferred credits - regulatory	17,696	9,395
Other deferred credits and other liabilities	24,533	25,413
Total deferred credits and other liabilities	157,705	109,061
Commitments and contingencies		
TOTAL CAPITALIZATION AND LIABILITIES	$ 626,126	$ 540,314

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

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

	Common Stock			Accumulated	Treasury Stock			
	Shares Issued	Amount	Other Paid-in Capital	Other Comprehensive Loss	Shares	Amount	Retained Earnings	Total
Balance, December 31, 2005	12,283,405	$ 73,695	$ 52,508	$ (414)	0	$ 0	$ 91,581	$ 217,370
Net Income							18,352	18,352
Other comprehensive income				305				305
Adjust to initially apply SFAS 158, net of tax				(435)				(435)
Common stock reacquired					2,249,975	(51,186)		(51,186)
Stock options exercised	79,335	476	920					1,396
Share-based compensation:								
Common and nonvested shares	20,061	126	295					421
Performance share plans			478					478
Dividends declared:								
Common - $0.69 per share							(6,971)	(6,971)
Non-redeemable preferred stock							(368)	(368)
Amortization of preferred stock issuance expenses			17					17
Loss on reacquisition of capital stock			7				(34)	(27)
Balance, December 31, 2006	12,382,801	$ 74,297	$ 54,225	$ (544)	2,249,975	$ (51,186)	$ 102,560	$ 179,352
Cumulative effect of adoption of FIN 48							120	120
Adjusted balance at Jan. 1, 2007	12,382,801	$ 74,297	$ 54,225	$ (544)	2,249,975	$ (51,186)	$ 102,680	$ 179,472
Net Income							15,804	15,804
Other comprehensive income				166				166
Dividend reinvestment plan	9,721	58	475		(19,847)	452		985
Stock options exercised	75,775	455	1,097					1,552
Share-based compensation:								
Common and nonvested shares	6,390	38	174					212
Performance share plans			333					333
Dividends declared:								
Common - $0.92 per share							(9,366)	(9,366)
Non-redeemable preferred stock							(368)	(368)
Amortization of preferred stock issuance expenses			17					17
Loss on reacquisition of capital stock			3				(3)	
Balance, December 31, 2007	12,474,687	$ 74,848	$ 56,324	$ (378)	2,230,128	$ (50,734)	$ 108,747	$ 188,807
Adjust to initially apply SFAS 158 measurement provision, net of tax				4			(46)	(42)
Net income							16,385	16,385
Other comprehensive income				146				146
Common stock issuance, net of issuance costs	1,190,000	7,140	13,760					20,900
Dividend reinvestment plan					(54,236)	1,233		1,233
Stock options exercised	67,050	402	882					1,284
Share-based compensation:								
Common & nonvested shares	3,891	23	65					88
Performance share plans	15,089	91	418					509
Dividends declared:								
Common - $0.92 per share							(9,500)	(9,500)
Cumulative non-redeemable preferred stock							(368)	(368)
Amortization of preferred stock issuance expense			17					17
Gain (loss) on capital stock			23				(3)	20
Balance, December 31, 2008	**13,750,717**	**$ 82,504**	**$ 71,489**	**$ (228)**	**2,175,892**	**$ (49,501)**	**$ 115,215**	**$ 219,479**

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - BUSINESS ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

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

Financial Statement Presentation The focus of the Consolidated Statements of Income is on the regulatory treatment of revenues and expenses as opposed to other enterprises where the focus is on income from continuing operations. Operating revenues and expenses (including related income taxes) are those items that ordinarily are included in the determination of revenue requirements or amounts recoverable from customers in rates. Operating expenses represent the costs of rendering service to be covered by revenue, before coverage of interest and other capital costs. Other income and deductions include non-utility operating results, certain expenses judged not to be recoverable through rates, related income taxes and costs (i.e. interest expense) that utility operating income is intended to cover through the allowed rate of return on equity rather than as a direct cost-of-service revenue requirement.

The focus of the Consolidated Balance Sheets is on utility plant and capital because of the capital-intensive nature of the regulated utility business. The prominent position given to utility plant, capital stock, retained earnings and long-term debt supports regulated ratemaking concepts in that utility plant is the rate base and capitalization (including long-term debt) is the basis for determining the rate of return that is applied to the rate base.

Basis of Consolidation The accompanying consolidated financial statements include the accounts of the company and its wholly subsidiaries. Inter-company transactions have been eliminated in consolidation. Jointly owned generation and transmission facilities are accounted for on a proportionate consolidated basis using our ownership interest in each facility. Our share of the assets, liabilities and operating expenses of each facility are included in the corresponding accounts on the accompanying consolidated financial statements.

Investments in entities over which we do not maintain a controlling financial interest are accounted for using the equity method when we have the ability to exercise significant influence over their operations. Under this method, we record our ownership share of the net income or loss of each investment in our consolidated financial statements. We have concluded that consolidation of these investments is not required under the provisions of FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities*, as revised ("FIN 46R"). See Part II, Item 8, Note 3 - Investments in Affiliates.

Variable Interest Entities The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. Transco and VYNPC are variable interest entities; however, we are not the primary beneficiary of these entities based on our assessments of the expected losses and expected residual returns to be absorbed by other entities under the various tariff agreements. Our maximum exposure to loss is the amount of our equity investments in Transco and VYNPC. See Part II, Item 8, Note 3 - Investments in Affiliates.

Use of Estimates The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosures of contingent assets and liabilities, and revenues and expenses. Actual results could differ from those estimates. In our opinion, areas where significant judgment is exercised include the valuation of unbilled revenue, pension plan assumptions, nuclear plant decommissioning liabilities, environmental remediation costs, regulatory assets and liabilities, and derivative contract valuations.

Regulatory Accounting Our utility operations are regulated by the Vermont Public Service Board ("PSB"), the Connecticut Department of Public Utility and Control and the Federal Energy Regulatory Commission ("FERC"), with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. As such, we prepare our financial statements in accordance with SFAS 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS 71"). The application of SFAS 71 results in differences in the timing of recognition of certain expenses from those of other businesses and industries. In order for us to report our results under SFAS 71, our rates must be designed to recover our costs of providing service, and we must be able to collect those rates from customers. If rate recovery of these costs becomes unlikely or uncertain, whether due to competition or regulatory action, this accounting standard would no longer apply to our regulated operations. In the event we determine that we no longer meet the criteria for applying SFAS 71, the accounting impact would be an extraordinary non-cash charge to operations of an amount that would be material unless stranded cost recovery is allowed through a rate mechanism. 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 SFAS 71 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 SFAS 71 and there is not a rate mechanism to recover these costs, the impact would, among other things, result in an extraordinary charge to operations of $8.9 million pre-tax at December 31, 2008. See Part II, Item 8, Note 7 - Retail Rates and Regulatory Accounting for additional information.

Unregulated Business Our non-regulated business, operated by Eversant Corporation ("Eversant"), a subsidiary of CRC, is SmartEnergy Water Heating Services, Inc., a water heater rental business operating in portions of Vermont and New Hampshire. Results of operations of Eversant and CRC are included in Other Income and Other Deductions on the Consolidated Statements of Income.

Income Taxes In accordance with SFAS No. 109, *Accounting for Income Taxes ("SFAS No. 109")*, we recognize deferred tax assets and liabilities for the cumulative effect of all temporary differences between financial statement carrying amounts and the tax basis of existing assets and liabilities using the tax rate expected to be in effect when the differences are expected to reverse. Investment tax credits associated with utility plant are deferred and amortized ratably to income over the lives of the related properties. We record a valuation allowance for deferred tax assets if we determine that it is more likely than not that such tax assets will not be realized.

During December 2008, we established a $0.2 million valuation allowance. At issue is the ability to utilize a Vermont State capital loss carryforward during the five-year carryforward period ending December 31, 2013. At this time we believe it is more likely than not that the capital loss carryforward will expire unused.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109* ("FIN 48"). FIN 48 clarifies the methodology to be used in estimating and reporting amounts associated with uncertain tax positions, including interest and penalties. We adopted FIN 48 on January 1, 2007 as required. Upon adoption and in accordance with FIN 48, we recognized the cumulative effect of approximately $0.1 million as an increase in the beginning balance of retained earnings related to a decrease in the liability for unrecognized tax benefits.

A reconciliation of the beginning and ending amount of gross unrecognized tax benefits follows (dollars in thousands):

	2008	2007
Balance at January 1	**$ 1,870**	$ 669
Reductions from lapse of the statute of limitations	**(74)**	(39)
Reductions due to the passage of time (depreciation)	**(134)**	0
Gross amount of increase as a result of current year tax positions	**0**	1,240
Balance at December 31	**$ 1,662**	$ 1,870

We had $0.4 million of unrecognized tax benefits that would affect the effective tax rate if recognized at both December 31, 2008 and 2007. During 2008, unrecognized tax benefits were reduced by $0.2 million which, due to the impact of deferred tax accounting, had a nominal impact on the effective tax rate.

We recognize interest related to unrecognized tax benefits as interest expense and penalties as other deductions. Accrued interest related to unrecognized tax benefits amounted to less than $0.1 million as of December 31, 2008 and 2007, and reflects the current year net interest expense on the Consolidated Statement of Income.

The Internal Revenue Service (IRS) completed its audit of the 2003, 2004 and 2005 tax years during 2008, resulting in nominal refunds due to us on the agreed portion of the audit. Our Casualty Loss refund claim was denied and is currently pending review at IRS Appeals. For federal tax purposes the 2003 tax year remains open to the IRS to exercise their right of offset for any amount awarded to us for the Casualty Loss claim for that year. The 2004 and 2005 tax years, although audited, technically remain open as well as the 2006 and 2007 tax years. For state tax purposes the 2005 though 2007 tax years remain open to examination by the states of New York, New Hampshire, Maine, Connecticut and Vermont. In the next 12 months we anticipate that $0.7 million of unrecognized tax benefits will be recognized due to lapse of the statute of limitations and passage of time (depreciation) of which $0.4 million will impact the effective tax rate.

During 2007, we determined that we would file amended returns related to the 2003 - 2006 tax years and increased unrecognized tax benefits by an additional $1.4 million. The unrecognized tax benefits established for the amended returns were subsequently reduced by $0.2 million during the third and fourth quarters of 2007 due to a true-up of the benefits previously recorded with the filed returns as well as part of the uncertainty of the tax position becoming certain via the passage of time. Because of the impact of deferred tax accounting, the disallowance of this item would not affect the effective tax rate.

Tax positions that were likely to reduce unrecognized tax benefits within 12 months of the reporting date are immaterial for further disclosure.

Revenue Recognition Revenues from the sale of electricity to retail customers are recorded when service is rendered or electricity is distributed. These are based on monthly meter readings, and estimates are made to accrue unbilled revenue at the end of each accounting period. We record contractual or firm wholesale sales in the month that power is delivered. We also engage in hourly sales and purchases in the wholesale markets administered by the New England Independent System Operator ("ISO-New England") through the normal settlement process. On a monthly basis, we aggregate these hourly sales and hourly purchases and report them as operating revenue and operating expenses.

Purchased Power We record the cost of power obtained under long-term contracts as operating expenses. These contracts do not convey to us the right to use the related property, plant or equipment. We engage in short-term purchases with other third parties and record them as operating expenses in the month the power is delivered. We also engage in hourly purchases through ISO-New England's normal settlement process. These are included in operating expenses.

Valuation of Long-Lived Assets We periodically evaluate the carrying value of long-lived assets, including our investments in nuclear generating companies, our unregulated investments, and our interests in jointly owned generating facilities, when events and circumstances warrant such a review. The carrying value of such assets is considered impaired when the anticipated undiscounted cash flow from such an asset is separately identifiable and is less than its carrying value. In that event, a loss is recognized based on the amount by which the carrying value exceeds the fair value of the long-lived asset. No impairments of long-lived assets were recorded in 2008 or 2007.

Utility Plant Utility plant is recorded at original cost. Replacements of retirement units of property are charged to utility plant. Maintenance and repairs, including replacements not qualifying as retirement units of property, are charged to maintenance expense. The costs of renewals and improvements of property units are capitalized. The original cost of units retired, net of salvage value, are charged to accumulated provision for depreciation. The primary components of utility plant at December 31 follow (dollars in thousands):

	2008	2007
Wholly owned electric plant in service:		
Distribution	**$ 301,070**	$ 288,548
Hydro facilities	**48,616**	47,759
Transmission	**45,044**	43,230
General	**34,788**	33,572
Intangible plant	**6,369**	6,776
Other	**4,693**	4,576
Subtotal wholly owned electric plant in service	**440,580**	424,461
Jointly owned generation and transmission units	**111,915**	110,830
Completed construction	**1,968**	2,895
Held for future use	**43**	43
Utility plant, at original cost	**554,506**	538,229
Accumulated depreciation	**(244,219)**	(235,465)
Property under capital leases, net	**6,133**	6,788
Construction work-in-progress	**24,632**	9,611
Nuclear fuel, net	**1,475**	1,105
Total Utility Plant, net	**$ 342,527**	$ 320,268

Property Under Capital Leases We record our commitments with respect to the Hydro-Quebec Phase I and II transmission facilities, and other equipment, as capital leases. At December 31, 2008 Property under Capital Leases was comprised of $24.6 million of original cost less $18.5 million of accumulated amortization. At December 31, 2007 Property under Capital Leases was comprised of $24.4 million of original cost less $17.6 million of accumulated amortization. See Part II, Item 8, Note 17 - Commitments and Contingencies.

Depreciation We use the straight-line remaining life method of depreciation. The total composite depreciation rate was 2.9 percent of the cost of depreciable utility plant in 2008, 2.89 percent in 2007 and 3.19 percent in 2006.

Allowance for Funds Used During Construction Allowance for funds used during construction ("AFUDC") is a non-cash item that is included in the cost of utility plant and represents the cost of borrowed and equity funds used to finance construction. Our AFUDC rates were 8.6 percent in 2008 and 2007, and 8.4 percent in 2006. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of interest expense on the Consolidated Statements of Income. The cost of equity funds is recorded as other income on the Consolidated Statements of Income.

Asset Retirement Obligations Changes to asset retirement obligations on the Consolidated Balance Sheets follow (dollars in thousands):

	2008	2007
Asset retirement obligations at January 1	**$ 3,200**	$ 3,041
Revisions in estimated cash flows	**(55)**	(2)
Accretion	**159**	235
Liabilities settled during the period	**(2)**	(74)
Asset retirement obligations at December 31	**$ 3,302**	$ 3,200

We have legal retirement obligations for decommissioning related to our joint-owned nuclear plant, Millstone Unit #3, and have an external trust fund dedicated to funding our share of future costs. The year-end aggregate fair value of the trust fund was $4.2 million in 2008 and $5.6 million in 2007, and is included in Investments and Other Assets on the Consolidated Balance Sheets.

We consider our past practices, industry practices, management's intent and the estimated economic lives of the assets in determining whether conditional asset retirement obligations can be reasonably estimated. Asset retirement obligations are recognized for items that can be reasonably estimated such as asbestos removal, disposal of polychlorinated biphenyls in certain transformers and breakers, and mercury in batteries and certain meters. We have not recorded an asset retirement obligation associated with asbestos abatement at certain of our sites because the range of time over which we may settle these obligations is unknown and cannot be reasonably estimated.

Non-legal Removal Costs: Our regulated operations collect removal costs in rates for certain utility plant assets that do not have associated legal asset retirement obligations. Non-legal removal costs of about $10 million in 2008 and $9 million in 2007 are included in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

Environmental Liabilities We are engaged in various operations and activities that subject us to inspection and supervision by both federal and state regulatory authorities including the United States Environmental Protection Agency. Our policy is to accrue a liability for those sites where costs for remediation, monitoring and other future activities are probable and can be reasonably estimated. See Part II, Item 8, Note 17 - Commitments and Contingencies.

Derivative Financial Instruments We account for certain power contracts as derivatives under the provisions of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted and SFAS 149, *Amendment of Statement 133 Derivative Instruments and Hedging Activities*, (collectively "SFAS 133"). These statements require that derivatives be recorded on the balance sheet at fair value. Our derivative financial instruments are related to managing our power supply resources to serve our customers, and are not for trading purposes. We have determined that these transactions do not qualify under the "normal" purchase and sale exception in SFAS 133. 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 forward energy contracts, one long-term purchased power contract that allows the seller to repurchase specified amounts of power with advance notice ("Hydro-Quebec Sellback #3") and financial transmission rights. All of our power-related derivatives are commodity contracts. For additional information about power-related derivatives, see Part II, Item 8, Note 5 - Fair Value.

Share-Based Compensation We adopted SFAS 123R, *Share-Based Payment* ("SFAS 123R"), on January 1, 2006, as required. Under SFAS 123R, share-based compensation costs are measured at the grant date based on the fair value of the award and recognized as expense on a straight-line basis over the requisite service period. See Note 8 - Share-Based Compensation.

Pension and Benefits Our defined benefit pension plans and postretirement welfare benefit plans are accounted for in accordance with FASB Statement No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)* ("SFAS No. 158") and FASB Staff Position ("FSP") FAS 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*. We use the fair value method to value all asset classes included in our pension and postretirement medical benefit trust funds. See Part II, Item 8, Note 15 - Pension and Postretirement Medical Benefits for more information.

Accumulated Other Comprehensive Loss ("AOCL") The employee benefit-related after-tax components of accumulated other comprehensive loss on the Consolidated Balance Sheets at December 31 follows (dollars in thousands):

	AOCL After-tax
Balance at December 31, 2006	**$ (544)**
Pension and postretirement medical benefit costs, net	166
Balance at December 31, 2007	**$ (378)**
Pension and postretirement medical benefit costs, net	150
Balance at December 31, 2008	**$ (228)**

Cash and Cash Equivalents We consider all liquid investments with an original maturity of three months or less when acquired to be cash and cash equivalents. Cash and cash equivalents consist primarily of cash in banks and money market funds.

Restricted Cash Restricted cash includes funds held by ISO-New England for performance assurance requirements described in Part II, Item 8, Note 17 - Commitments and Contingencies.

Special Deposits Special deposits include mandatory sinking fund payments of $1 million in 2008 and in 2007 for our preferred stock subject to mandatory redemption.

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

Other Income: The components of Other income on the Consolidated Statements of Income for the years ended December 31 follow (dollars in thousands):

	2008	2007	2006
Interest on temporary investments	**$ 257**	$ 273	$ 1,603
Non-utility revenue and non-operating rental income	**1,901**	1,842	1,878
Amortization of contributions in aid of construction - tax adder	**991**	951	888
Other interest and dividends	**148**	372	511
Gain on sale of non-utility property	**7**	105	317
Miscellaneous other income	**294**	270	290
Total	**$ 3,598**	$ 3,813	$ 5,487

Other Deductions: The components of Other deductions on the Consolidated Statements of Income for the years ended December 31 follow (dollars in thousands):

	2008	2007	2006
Supplemental retirement benefits and insurance	**$ 3,041**	$ 785	$ 568
Non-utility expenses	**1,294**	1,183	1,281
Realized losses on available-for-sale securities	**0**	0	151
Miscellaneous other deductions	**470**	513	401
Total	**$ 4,805**	$ 2,481	$ 2,401

Prepayments: The components of Prepayments on the Consolidated Balance Sheets at December 31 follow (dollars in thousands):

	2008	2007
Taxes	**$ 14,924**	$ 5,361
Insurance	**1,310**	2,869
Miscellaneous	**1,133**	712
Total	**$ 17,367**	$ 8,942

Other Current Liabilities: The components of Other current liabilities on the Consolidated Balance Sheets at December 31 follow (dollars in thousands):

	2008	2007
Deferred compensation plans and other	**$ 2,623**	$ 2,655
Accrued employee-related costs	**4,946**	4,367
Other taxes and Energy Efficiency Utility	**5,882**	3,264
Cash concentration account - outstanding checks	**3,701**	740
Obligation under capital leases	**942**	899
December 2008 storm accrual	**3,491**	0
Miscellaneous accruals	**12,060**	8,836
Total	**$ 33,645**	$ 20,761

Other Deferred Credits and Other Liabilities: The components of Other deferred credits and other liabilities on the Consolidated Balance Sheets at December 31 follow (dollars in thousands):

	2008	2007
Environmental reserve	**$ 973**	$ 1,097
Non-legal removal costs	**9,954**	8,990
Contribution in aid of construction - tax adder	**5,210**	5,423
Reserve for loss on power contract	**7,175**	8,371
Accrued income taxes and interest	**683**	718
Provision for rate refund	**234**	778
Other	**304**	36
Total	**$ 24,533**	$ 25,413

Dividends Declared Per Share of Common Stock: The timing of common stock dividend declarations fluctuates whereas the dividend payments are made on a quarterly basis. In 2008 and 2007, we declared and paid cash dividends of 92 cents per share of common stock. In 2006, we declared cash dividends of 69 cents per share and paid cash dividends of 92 cents per share of common stock.

Supplemental Cash Flow Information: Cash paid for interest and income tax as of December 31 follows (dollars in thousands):

	2008	2007	2006
Interest (net of amounts capitalized)	**$ 10,716**	$ 8,073	$ 8,109
Income taxes (net of refunds)	**$ 3,142**	$ 6,162	$ 6,300

Construction and plant expenditures on the Consolidated Statements of Cash Flows reflect actual payments made during the periods. Construction and plant-related expenditures are accrued at the end of each reporting period. At December 31, 2008, less than $0.1 million of construction and plant-related accruals was included in Accounts Payable, and $2.1 million was included in Other Current Liabilities. At December 31, 2007, $0.9 million of construction and plant-related accruals was included in Accounts Payable, and $0.3 million was included in Other Current Liabilities.

During 2008, we acquired $0.3 million of computer equipment through a capital lease agreement. We also recorded retirements under the Phase II capital lease of $0.1 million, which reduced the related asset and liability.

We maintain a cash concentration account for payments related to our routine business activities. The book overdraft amount resulting from outstanding checks is recorded as a current liability at the end of each reporting period. Changes in the book overdraft position are reflected in operating activities on the Consolidated Statements of Cash Flows.

Other non-cash expense and (income), net includes provision for uncollectible accounts, the change in cash surrender value of life insurance policies held in our Rabbi Trust, share-based compensation and environmental reserve adjustments. Other investing activities include return of capital from investments in affiliates, changes in restricted cash related to investing activities and non-utility capital expenditures. Other financing activities include reductions in capital lease obligations and the net change in special deposits related to mandatory preferred stock redemptions.

Reclassifications

Certain prior year amounts have been reclassified to conform to the current year presentation. Power-related derivatives of $0.7 million have been reclassified from Other current assets to a separate line on the December 31, 2007 Consolidated Balance Sheet.

Recently Adopted Accounting Policies

Fair Value: On January 1, 2008, we adopted FASB Statement No. 157, *Fair Value Measurements* (“SFAS 157”), which addresses how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under U.S. GAAP. This standard applies prospectively to new fair value measures of financial instruments and recurring fair value measurements of non-financial assets and non-financial liabilities. SFAS 157 does not expand the use of fair value, but it has applicability to several current accounting standards that require or permit us to measure assets and liabilities at fair value.

SFAS 157 defines fair value as “the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date,” or the “exit price.” We must determine the fair value of an asset or liability based on the assumptions that market participants would use in pricing the asset or liability (if available), and not on our assumptions. The identification of market participant assumptions provides a basis for determining the inputs to be used in pricing each asset or liability. SFAS 157 also establishes a three-level fair value hierarchy, reflecting the extent to which inputs to the determination of fair value can be observed, and requires fair value disclosures based upon this hierarchy. The adoption of SFAS 157 did not have a material impact on our financial position, results of operations and cash flows. See Part II, Item 8, Note 5 - Fair Value for additional information.

On February 12, 2008, the FASB issued FASB Staff Position No. FAS 157-2, *Effective Date of FASB Statement No. 157*, which amends SFAS 157 by allowing entities to delay its effective date by one year for non-financial assets and non-financial liabilities, except for items that are recognized or disclosed at fair value in the consolidated financial statements on a recurring basis. As permitted, we deferred the application of SFAS 157 related to asset retirement obligations until January 1, 2009. We don't expect the adoption of SFAS 157-2 to have a material impact on our financial position, results of operations and cash flows.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (“SFAS 159”). SFAS 159 establishes a fair value option under which entities can elect to report certain financial assets and liabilities at fair value, with changes in fair value recognized in earnings. On January 1, 2008, SFAS 159 became effective; however, we did not elect the fair value option for any of our financial assets or liabilities.

Pension and Postretirement: We adopted the recognition and disclosure provisions of SFAS No. 158 *Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)* (“SFAS 158”) as of December 31, 2006. SFAS 158 requires companies to measure plan assets and benefit obligations as of the same date as their fiscal year-end balance sheet. We adopted the measurement provisions on January 1, 2008. Changing the annual benefit measurement date from September 30, 2008 to December 31, 2008 resulted in a pre-tax charge of $1.3 million, of which $0.1 million was recorded to retained earnings. Our pension and postretirement medical plans were remeasured as of December 31, 2008. In our most recent retail rate proceeding we received approval for recovery of the regulated utility portion of the impact resulting from the change in measurement date. Accordingly, we recorded a regulatory asset of $1.2 million in the first quarter of 2008 with a 5-year amortization period that commenced on February 1, 2008.

FSP FAS 140-4 and FIN 46(R)-8: In December 2008, the FASB issued FSP 140-4 and FIN(R)-8, *Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities*, (“FSP FAS 140-4 and FIN 46(R)-8”). This pronouncement amends FASB Statement No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, requiring that public entities provide additional disclosures about the transfer of financial assets. FSP FAS 140-4 and FIN 46(R)-8 also amend FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, requiring public enterprises to provide additional disclosures about their involvement with variable interest entities and qualifying special purpose entities. FSP FAS 140-4 and FIN 46(R)-8 are effective for the year ended December 31, 2008. The adoption of this standard did not have a material impact on our consolidated financial statements since it only requires additional disclosures. As a result, we have provided additional disclosures for our investments in Transco and VYNPC. See Part II, Item 8, Note 1 - Business Organization and Summary of Significant Accounting Policies - Variable Interest Entities above and Part II, Item 8, Note 3 - Investments in Affiliates.

Recent Accounting Pronouncements Not Yet Adopted

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

SFAS 160: In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51* ("SFAS 160"). SFAS 160 states that minority interests will be recharacterized as noncontrolling interests and classified as a component of equity. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. It requires that once a subsidiary is deconsolidated, any retained noncontrolling equity investment in the former subsidiary be initially measured at fair value. SFAS 160 is effective as of the beginning of an entity's first fiscal year beginning on or after December 15, 2008 (beginning January 1, 2009 for us). We are currently evaluating the requirements of SFAS 160 and have not yet determined the impact, if any, that the adoption may have on our consolidated financial statements.

SFAS 161: In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133* ("SFAS 161"). SFAS 161 requires enhanced disclosures about an entity's derivative and hedging activities. The provisions of SFAS 161 will become effective for disclosures in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2009.

SFAS 162: In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* ("SFAS 162"). SFAS 162 identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presently in conformity with U.S. GAAP. SFAS 162 is effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles*. We do not believe that implementation of SFAS 162 will have any impact on our consolidated financial statements.

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

NOTE 2 - EARNINGS PER SHARE ("EPS")

The 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 common shares outstanding for the period. Diluted EPS follows a similar calculation except that the weighted-average common shares are increased by the number of potentially dilutive common shares. The table below provides a reconciliation of the numerator and denominator used in calculating basic and diluted EPS for the years ended December 31 (dollars in thousands, except share information):

	2008	2007	2006
Numerator for basic and diluted EPS:			
Income from continuing operations	**$ 16,385**	$ 15,804	$ 18,101
Dividends declared on preferred stock	**368**	368	368
Net income from continuing operations available for common stock	**$ 16,017**	$ 15,436	$ 17,733
Denominators for basic and diluted EPS:			
Weighted-average basic shares of common stock outstanding	**10,458,220**	10,185,930	10,756,027
Dilutive effect of stock options	**55,525**	132,302	66,971
Dilutive effect of performance shares	**22,386**	31,959	4,184
Weighted-average diluted shares of common stock outstanding	**10,536,131**	10,350,191	10,827,182

There were 12,180 performance shares excluded in 2008 because they were antidilutive. All outstanding stock options were included in the computation in 2007 because the exercise prices were below the average market price of the common shares. In 2006, there were 60,077 shares excluded from the computation.

NOTE 3 - INVESTMENTS IN AFFILIATES

Our equity method investments and equity in earnings from those investments follow (dollars in thousands):

		Investment At December 31		**Equity in Earnings As of December 31**		
	Direct Ownership	**2008**	2007	**2008**	2007	2006
Vermont Electric Power Company, Inc.:						
Common stock	47.05%	**$ 11,257**	$ 11,257			
Preferred stock	48.03%	**$ 267**	$ 277			
Subtotal		**11,524**	11,534	**$ 1,296**	$ 1,404	$ 1,324
Vermont Transco LLC (a)	33.02%	**87,597**	78,784	**14,806**	4,482	1,500
Vermont Yankee Nuclear Power Corporation	58.85%	**2,763**	2,804	**144**	431	441
Connecticut Yankee Atomic Power Company	2.00%	**259**	250	**9**	94	(61)
Maine Yankee Atomic Power Company	2.00%	**34**	29	**6**	8	31
Yankee Atomic Electric Company	3.50%	**55**	51	**3**	11	5
Total Investments in Affiliates		**$ 102,232**	$ 93,452	**$ 16,264**	$ 6,430	$ 3,240

(a) Ownership percentage was 39.79 percent at December 31, 2007 and 29.86 percent at December 31, 2006.

Undistributed earnings of these affiliates, included in Retained Earnings on our Consolidated Balance Sheets, amounted to $8.5 million at December 31, 2008 and $2.9 million at December 31, 2007. Of these amounts, $8.2 million at December 31, 2008 and $2.5 million at December 31, 2007 were from our investment in Transco.

VELCO and Transco VELCO, through its wholly owned subsidiary, Vermont Electric Transmission Company, Inc., and Transco own and operate an integrated transmission system in Vermont over which bulk power is delivered to all electric utilities in the state. Transco, a Vermont limited liability company, was formed by VELCO and its owners. In June 2006, VELCO transferred its assets to Transco in exchange for 2.4 million Class A Units, and Transco assumed all of VELCO's debt. VELCO and its employees now manage the operations of Transco under a Management Services Agreement between VELCO and Transco. Transco operates under an Operating Agreement among us, VELCO, Transco, Green Mountain Power and most of the other Vermont electric utilities. Transco also operates under the Amended and Restated Three Party Agreements, assigned to Transco from VELCO, among us, Green Mountain Power, VELCO and Transco.

We invested $3.1 million in Transco in 2008 and $53 million in 2007. Our direct ownership interest was 33.02 percent at December 31, 2008 and 39.79 percent at December 31, 2007. Our ownership interest in Transco is represented by Class A Units that receive a return on equity investments of 11.5 percent under the 1991 Transmission Agreement ("VTA"). At December 31, 2008, our total direct and indirect interest in Transco was 39.67 percent. It was 45.68 percent at December 31, 2007. Transco is a variable interest entity but we are not the primary beneficiary.

Cash dividends received from VELCO were $1.3 million in 2008, 2007 and 2006. VELCO's consolidated revenues shown in the table below include billings to us from VELCO of $0 million in 2008 and 2007 and $1.2 million in 2006. They also include Transco's billings to us of $7.3 million in 2008 and $5.1 million in 2007 and a net credit of $1.5 million in 2006. These amounts are included in Transmission - affiliates on our Consolidated Statements of Income. Accounts payable to VELCO were $5.6 million at December 31, 2008 and $5.7 million at December 31, 2007.

VELCO's summarized consolidated financial information (including Transco) at December 31 follows (dollars in thousands):

	2008	2007	2006
Operating revenues	**$ 75,660**	$ 51,911	$ 35,808
Operating income	**$ 40,088**	$ 21,922	$ 13,467
Income before non-controlling interest and income tax	**$ 35,688**	$ 13,955	$ 8,000
Less members' non-controlling interest in income	**30,712**	9,483	3,245
Less income tax	**2,175**	1,661	1,888
Net income	**$ 2,801**	$ 2,811	$ 2,867

	2008	2007
Current assets	**$ 34,687**	$ 50,467
Non-current assets	**496,316**	395,923
Total assets	**531,003**	446,390
Less:		
Current liabilities	**63,725**	34,384
Non-current liabilities	**220,443**	215,014
Members' non-controlling interest	**222,409**	172,592
Net assets	**$ 24,426**	$ 24,400

Transco's summarized financial information (included above in VELCO's summarized consolidated financial information) for 2008, 2007 and 2006 (from inception at June 30 to December 31) follows (dollars in thousands).

	2008	2007	2006
Operating revenues	**$ 75,200**	$ 51,466	$ 18,330
Operating income	**$ 40,088**	$ 21,922	$ 7,950
Net income	**$ 35,647**	$ 13,904	$ 5,527

	2008	2007
Current assets	**$ 33,791**	$ 39,354
Non-current assets	**485,405**	389,351
Total assets	**519,196**	428,705
Less:		
Current liabilities	**49,179**	21,120
Non-current liabilities	**210,339**	209,383
Mandatorily redeemable membership units	**10,000**	0
Net assets	**$ 249,678**	$ 198,202

Transmission services provided by Transco are billed to us under the 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. In June 2007, FERC issued an order combining three FERC filings related to the VTA, including a request by five municipal utilities for FERC approval to withdraw from the VTA and take transmission service under a different tariff, and requests by Transco for revisions to the VTA. The parties reached a preliminary settlement in January 2008 and filed a definitive settlement agreement with the FERC in March 2008. The settlement agreement is supported by all parties, including us, and resolves all issues that were raised in the FERC proceedings. The FERC approved the settlement agreement on August 22, 2008, and related amendments to the Transco operating agreement necessary to implement the settlement have been approved by the PSB.

Transco's billings to us primarily include the VTA and charges and reimbursements under the NEPOOL Open Access Transmission Tariff ("NOATT"). Transco's billings to us in 2008, 2007 and 2006 are described above. Accounts payable to Transco were $0.4 million at December 31, 2008 and $1.8 million at December 31, 2007. Cash dividends received were $9.1 million in 2008, $3.1 million in 2007 and $0.4 million in 2006.

VYNPC VYNPC sold its nuclear plant to Entergy Nuclear Vermont Yankee, LLC ("Entergy-Vermont Yankee") in July 2002. The sale agreement included a purchased power contract ("PPA") between VYNPC and Entergy-Vermont Yankee. Under the PPA, VYNPC pays Entergy-Vermont Yankee for generation at fixed rates, and in turn, bills the PPA charges from Entergy-Vermont Yankee with certain residual costs of service through a FERC tariff to the VYNPC sponsors, including us. The residual costs of service include VYNPC's other operating expenses, including any expenses incurred in administering the PPA and the power contracts, and an allowed return on equity. Our entitlement to energy produced by the Vermont Yankee plant is about 29 percent. See Part II, Item 8, Note 17 - Commitments and Contingencies.

Although we own a majority of the shares of VYNPC, the power contracts, sponsor agreement and composition of the board of directors, under which it operates, effectively restrict our ability to exercise control over VYNPC. VYNPC is a variable interest entity, but we are not the primary beneficiary.

VYNPC's summarized financial information at December 31 follows (dollars in thousands):

	2008	2007	2006
Operating revenues	**$ 166,104**	$ 160,143	$ 201,325
Operating income	**$ (543)**	$ 3,130	$ 3,513
Net income	**$ 245**	$ 733	$ 748

	2008	2007
Current assets	**$ 28,102**	$ 31,121
Non-current assets	**140,291**	135,092
Total assets	**168,393**	166,213
Less:		
Current liabilities	**16,009**	16,325
Non-current liabilities	**147,689**	145,123
Net assets	**$ 4,695**	$ 4,765

VYNPC's revenues shown in the table above include sales to us of $57.7 million in 2008, $55.8 million in 2007 and $70.1 million in 2006. These amounts are included in Purchased power - affiliates on our Consolidated Statements of Income. Also included in VYNPC's revenues above are sales of $0.3 million each year representing a small portion of our entitlement received by a secondary purchaser. Accounts payable to VYNPC were $5.3 million at December 31, 2008 and $5.6 million at December 31, 2007. Cash dividends received were $0.2 million in 2008 and $0.4 million in 2007 and 2006.

Maine Yankee, Connecticut Yankee and Yankee Atomic We are responsible for paying our ownership percentage of decommissioning and all other costs for Maine Yankee, Connecticut Yankee and Yankee Atomic. These plants are permanently shut down. All three collect decommissioning and closure costs through FERC-approved wholesale rates charged under power purchase agreements with us and several other New England utilities. Historically, our share of these costs has been recovered from retail customers through PSB-approved rates. We believe based on historical rate recovery that our share of decommissioning and closure costs for each plant will continue to be recovered through the regulatory process. However, if the FERC disallows recovery of any of these costs in their wholesale rates, there is a risk that the PSB would disallow recovery of our share in retail rates. Information related to estimated decommissioning and closure costs for each plant based on their most recent FERC-approved rate settlements is shown below (dollars in millions):

	Remaining Obligations	Revenue Requirements	Company Share
Maine Yankee	$ 123.9	$ 67.3	$ 1.3
Connecticut Yankee	$ 152.9	$ 312.1	$ 6.2
Yankee Atomic	$ 106.1	$ 70.5	$ 2.5

The remaining obligations are the estimated remaining total costs to be incurred by the respective Yankee companies to operate the supporting organization and decommission the plant, including onsite spent fuel storage, in 2008 dollars for the period 2009 through 2023 for Maine Yankee and Connecticut Yankee and through 2022 for Yankee Atomic. Revenue requirements are the estimated future payments by the sponsors to fund estimated FERC-approved decommissioning and other costs (in nominal dollars) for 2009 through 2013 for Maine Yankee, 2015 for Connecticut Yankee and 2014 for Yankee Atomic. Revenue requirements include Maine Yankee and Connecticut Yankee collections for required contributions to pre-1983 spent fuel funds. Yankee Atomic has already collected and paid these required pre-1983 contributions. These estimates may be revised from time to time based on information available to the company regarding estimated future costs. Our share of the estimated costs shown in the table above is included in regulatory assets and nuclear decommissioning liabilities (current and non-current) on the Consolidated Balance Sheets.

Maine Yankee: Maine Yankee's wholesale rates are currently based on a September 2004 FERC-approved settlement. Our share of decommissioning and other costs amounted to $0.9 million in 2008, $1.1 million in 2007 and $1.3 million in 2006. These amounts are included in Purchased power - affiliates on the Consolidated Statements of Income. There was no return of capital in the form of common stock redemptions in 2008. Return of capital in the form of common stock redemptions was $0.3 million in 2007.

Plant decommissioning activities were completed in 2005 and the Nuclear Regulatory Commission ("NRC") amended Maine Yankee's operating license in October 2005 for operation of the Independent Spent Fuel Storage Installation. This amendment reduced the size of the licensed property to include only the land immediately around the Independent Spent Fuel Storage Installation. Maine Yankee remains responsible for safe storage of the plant's spent nuclear fuel and waste at the site until the United States Department of Energy ("DOE") meets its obligation to remove the material from the site.

Connecticut Yankee: Connecticut Yankee's wholesale rates are currently based on a 2006 FERC-approved settlement. The notable provisions of the settlement included: 1) reduced decommissioning collections to reflect a lower escalation factor beginning January 1, 2007; 2) resolution of any claims of imprudence made in the docket against Connecticut Yankee in its decommissioning effort with no finding of imprudence; 3) reduced decommissioning collections in 2007 through 2009 to credit ratepayers with a $15 million settlement payment from Bechtel Power Corporation; 4) a budget incentive plan to reduce the decommissioning collections by $10 million wherein timely license termination performance by Connecticut Yankee would offset some of that amount; 5) an investment earnings tracking mechanism for performance greater than or less than certain targets; and 6) resumption of reasonable payments of dividends by Connecticut Yankee to its stockholders subject to certain incentive target balances.

Our share of decommissioning and other costs amounted to $0.8 million in 2008, $1 million in 2007 and $2.4 million in 2006. These amounts are included in Purchased power - affiliates on the Consolidated Statements of Income. Dividends from Connecticut Yankee were zero in 2008 and $0.1 million in 2007.

Plant decommissioning activities were completed in 2007 and the NRC amended Connecticut Yankee's operating license in November 2007 for operation of the Independent Spent Fuel Storage Installation. This amendment reduced the size of the licensed property to include only the land immediately around the Independent Spent Fuel Storage Installation. Connecticut Yankee remains responsible for safe storage of the plant's spent nuclear fuel and waste at the site until the DOE meets its obligation to remove the material from the site.

Yankee Atomic: Yankee Atomic's wholesale rates are currently based on a 2006 FERC-approved settlement. Based on the approved settlement, Yankee Atomic agreed to reduce its revenue requirements by $79 million for the period 2006-2010 and to increase its revenue requirements by $47 million for the period 2011-2014. The revision includes adjustments for contingencies, projected escalation and certain decontamination and dismantling expenses. The approved settlement also provides for reconciling and adjusting future charges based on actual decontamination and dismantling expenses and the decommissioning trust fund's actual investment earnings. Our share of decommissioning and other costs amounted to $0.4 million in 2008 and 2007 and $1.7 million in 2006. These amounts are included in Purchased power - affiliates on the Consolidated Statements of Income.

Plant decommissioning activities were completed in 2007 and the NRC amended Yankee Atomic's operating license in August 2007 for operation of the Independent Spent Fuel Storage Installation. This amendment reduced the size of the licensed property to include only the land immediately around the Independent Spent Fuel Storage Installation. Yankee Atomic remains responsible for safe storage of the plant's spent nuclear fuel and waste at the site until the DOE meets its obligation to remove the material from the site.

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 material from the nuclear plants no later than January 31, 1998 in return for payments by each company into the nuclear waste fund. No spent fuel or Greater than Class C material has been collected by the DOE, and is being stored at each of the plants. 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 retail customers.

On October 4, 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. The three companies had claimed actual damages through the same periods in the amounts of $78.1 million for Maine Yankee, $37.7 million for Connecticut Yankee and $60.8 million for Yankee Atomic. On December 4, 2006, the DOE filed a notice of appeal to the United States Court of Appeals for the Federal Circuit ("Appeals Court") in all three cases, and on December 14, 2006, all three companies filed notices of cross appeals.

On February 9, 2007, the Appeals Court issued an order consolidating the three cases. Later in 2007, the Appeals Court issued orders making two other cases companion appeals. Oral arguments on the pending appeals were held in February 2008. On August 7, 2008, the Appeals Court reversed the reward of damages and remanded the cases back to the trial courts. The remand directed the trial courts to apply the acceptance rate in the 1987 annual capacity reports when determining damages. On January 30, 2009, the Court of Federal Claims issued an order reserving weeks in August, 2009, for pre-trial conference, trial and any other proceedings necessary for final resolutions of the issues involved in the remanded cases. Due to the complexity of the issues and the potential for further appeals, the three companies cannot predict the amount of damages that will actually be received or the timing of the final determination of such damages. Each of the companies' respective FERC settlements require that damage payments, net of taxes and net of further spent fuel trust funding, be credited to ratepayers including us. We expect that our share of these payments, if any, would be credited to our ratepayers as well.

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

NOTE 4 - FINANCIAL INSTRUMENTS

The estimated fair values of financial instruments at December 31 follow (dollars in thousands):

	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Power contract derivative assets (includes current portion)	$ 12,891	$ 12,891	$ 707	$ 707
Power contract derivative liabilities (includes current portion)	$ 4,071	$ 4,071	$ 7,817	$ 7,817
Preferred stock subject to mandatory redemption (includes current portion)	$ 2,000	$ 2,003	$ 3,000	$ 2,975
Long-term debt:				
First mortgage bonds (includes current portion)	$ 167,500	$ 159,172	$ 110,500	$ 114,279
New Hampshire Industrial Development Authority Bonds	$ 5,450	$ 5,383	$ 5,450	$ 5,371

The estimated fair values of power contract derivatives are based on over-the-counter quotes or broker quotes at the end of the reporting period, with the exception of one long-term power contract that is valued using a binomial tree model and quoted market data when available, along with appropriate valuation methodologies. In 2008, the fair values were unrealized losses of $4.1 million that were recorded as liabilities on the Consolidated Balance Sheet and unrealized gains of $12.9 million that were recorded as assets on the Consolidated Balance Sheet. In 2007, the fair values were unrealized losses of $7.8 million that were recorded as liabilities on the Consolidated Balance Sheet and unrealized gains of $0.7 million that were recorded as assets on the Consolidated Balance Sheet.

The fair values of our fixed rate securities 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 and cash equivalents, restricted cash, special deposits, receivables and payables. The carrying values approximate fair value because of the short maturity of those instruments. Also, the carrying value of notes payable approximates fair value since the rates are adjusted at least monthly.

Concentration Risk Financial instruments that potentially expose us to concentrations of credit risk consist primarily of cash, cash equivalents, special deposits and accounts receivable.

Our accounts receivable are not collateralized. As of December 31, 2008, approximately 5 percent of total accounts receivable are with wholesale entities engaged in the energy industry. This industry concentration could affect our overall exposure to credit risk, positively or negatively, since customers may be similarly affected by changes in economic, industry or other conditions.

Our practice to mitigate credit risk arising from our energy industry concentration with wholesale entities is to contract with creditworthy power and transmission counterparties or obtain deposits or guarantees from their affiliates. We may also enter into third-party power purchase and sales contracts that require collateral based on credit rating or contain master netting arrangements in the event of nonpayment. Currently, we hold parental guarantees from certain transmission customers and forward power sale counterparties.

Our material power supply contracts and arrangements are principally with Hydro-Quebec and VYNPC. These contracts comprise the majority of our total energy (mWh) purchases. These supplier concentrations could have a material impact on our power costs, if one or both of these sources were unavailable over an extended period of time. We do not have the ability to seek collateral under these two contracts, but the contracts provide the ability to seek damages for non-performance.

NOTE 5 - FAIR VALUE

Effective January 1, 2008, we adopted SFAS 157 as required. SFAS 157 establishes a single, authoritative definition of fair value, prescribes methods for measuring fair value, establishes a fair value hierarchy based on the inputs used to measure fair value and expands disclosures about the use of fair value measurements; however, SFAS 157 does not expand the use of fair value accounting in any new circumstances. SFAS 157 defines fair value as “the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.”

Valuation Techniques SFAS 157 emphasizes that 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. SFAS 157 provides guidance on 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 SFAS 157 establishes a fair value hierarchy ("hierarchy") to prioritize the inputs used in valuation techniques. The hierarchy is designed to indicate the relative reliability of the fair value measure. The highest priority is given to quoted prices in active markets, and the lowest to unobservable data, such as an entity's internal information. The lower the level of the input of a fair value measurement, the more extensive the disclosure requirements. There are three broad levels:

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

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

Level 3: Pricing inputs include significant inputs that are generally less observable. Unobservable inputs may be used to measure the asset or liability where observable inputs are not available. We develop these inputs based on the best information available, including our own data. Level 3 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 December 31, 2008			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Millstone decommissioning trust fund	$ 0	$ 4,203	$ 0	$ 4,203
Cash equivalents	5,028	0	0	5,028
Restricted cash	3,636	0	0	3,636
Power-related derivatives - current	0	0	12,758	12,758
Power-related derivatives - long term	0	0	133	133
Total	$ 8,664	$ 4,203	$ 12,891	$ 25,758
Liabilities:				
Power-related derivatives - current	$ 0	$ 0	$ 2	$ 2
Power-related derivatives - long term	0	0	4,069	4,069
Total	$ 0	$ 0	$ 4,071	$ 4,071

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

Cash Equivalents and Restricted Cash We use the market approach to measure the fair values of money market funds, included in cash equivalents and restricted cash. Cash equivalents are included in cash and cash equivalents on the Consolidated Balance Sheets. We are able to obtain actively traded quoted prices for these funds.

Power-related Derivatives We estimate the fair values of power-related derivatives based on the best market information available, including the use of internally developed models and broker quotes for forward energy contracts. At the end of 2008 and 2007, we value financial transmission rights using auction clearing prices from the December auctions held by ISO-New England. We also use a binomial tree model and an internally developed long-term price forecast to value a power-related option contract.

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

		2008
Balance at Beginning of Period	**$**	**(7,110)**
Gains and losses (realized and unrealized)		**7,189**
Purchases, sales, issuances and net settlements		**8,741**
Balance at December 31	**$**	**8,820**
Net realized (losses) gains relating to instruments still held during the period	$	0

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 Consolidated Balance Sheet, depending on whether the change in fair value is a 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 is required to 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 ratepayers and are recorded as regulatory assets or liabilities in accordance with SFAS No. 71.

FASB Staff Position Nos. 115-1 and 124-1, *The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments,* state that 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 hold individual securities in the trusts because regulatory authorities limit our ability to oversee the day-to-day management of our nuclear decommissioning trust fund investments. For the majority of the investments shown below, we own a share of the trust fund investments and do not hold individual securities. We consider all securities held by our nuclear decommissioning trusts with fair values below their cost basis to be other-than-temporarily impaired. We recorded an impairment of $0.4 million on our Millstone securities in 2008.

The fair value of these investments at December 31 is summarized below (dollars in thousands):

	2008				2007			
Security Types	**Amortized Cost**	**Unrealized Gains**	**Unrealized Losses**	**Estimated Fair Value**	Amortized Cost	Unrealized Gains	Unrealized Losses	Estimated Fair Value
Equity Securities	**$ 2,406**	**$ 240**	**$ 0**	**$ 2,646**	$ 2,691	$ 1,467	$ 0	$ 4,158
Debt Securities	**1,407**	**90**	**0**	**1,497**	1,413	44	0	1,457
Cash and other	**60**	**0**	**0**	**60**	30	0	0	30
Total	**$ 3,873**	**$ 330**	**$ 0**	**$ 4,203**	$ 4,134	$ 1,511	$ 0	$ 5,645

Information related to the fair value of debt securities at December 31, 2008 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	$ 42	$ 245	$ 320	$ 890	$ 1,497

NOTE 7 - RETAIL RATES AND REGULATORY ACCOUNTING

Retail Rates Our retail rates are set by the Vermont Public Service Board (“PSB”) after considering the recommendations of Vermont’s consumer advocate, the Vermont Department of Public Service (“DPS”). Fair regulatory treatment is fundamental to maintaining our financial stability. Rates must be set at levels to recover costs, including a market rate of return to equity and debt holders, in order to attract capital. The return on common equity of our regulated business did not exceed the allowed return for 2008, 2007 or 2006.

On January 31, 2008, the PSB issued an order approving a settlement agreement that we previously reached with the Vermont Department of Public Service (“DPS”). The settlement included, among other things, a 2.30 percent rate increase (resulting in an anticipated additional revenue of $6.4 million on an annual basis) effective February 1, 2008 and a 10.71 percent rate of return on equity, capped until our next rate proceeding or approval of the alternative regulation plan proposal that we submitted on August 31, 2007. We also agreed to conduct an independent business process review to assure our cost controls are sufficiently challenging and that we are operating efficiently.

The business process review commenced in April 2008 and concluded in October 2008. The final report, which was generally positive about company operations, included 51 recommendations for improvement covering a wide range of areas in the company. We are collaborating on the implementation of these recommendations with the DPS and we have filed an implementation update with the PSB. The cost of the review, approximately $0.4 million, did not affect our income statement because the costs have been deferred for future recovery in rates.

On September 30, 2008, the PSB issued an order approving, with modifications, the alternative regulation plan proposal that we submitted in August 2007. The plan became effective on November 1, 2008. It expires on December 31, 2011, but we have an option to petition for an extension beyond 2011. The plan replaces the traditional ratemaking process and allows for annual base rate adjustments, quarterly rate adjustments to reflect changes in power supply and transmission-by-others costs and annual rate adjustments to reflect changes, within predetermined limits, from the allowed earnings level. The allowed return on equity was reduced from 10.71 percent to 10.21 percent as of the effective date of the plan, per a settlement agreement that we reached with the DPS. Under the plan, the allowed return on equity will be adjusted annually to reflect one half of the change in the yield on the 10-year Treasury note as measured over the last 20 trading days prior to October 15 of each year. The earnings sharing adjustment mechanism within the plan provides for the return on equity of the regulated portion of our business to fall between 75 basis points above or below the allowed return on equity before any adjustment is made. If the actual return on equity of the regulated portion of our business exceeds 75 basis points above the allowed return, the excess amount is returned to ratepayers in a future period. If the actual return on equity of our regulated business falls between 75 and 100 basis points below the allowed return on equity, the shortfall is shared equally between shareholders and ratepayers. Any earnings shortfall in excess of 100 basis points below the allowed return on equity is recovered from ratepayers. These adjustments are made at the end of each fiscal year.

The plan encourages efficiency in operations. It also includes provisions under for us to contribute, under certain circumstances, to a to-be-established low-income bill-assistance program; to develop an annual fixed-power-price option for retail consumers; and to track and report annually on the number of retail customers affected by supplier-caused outages. In its order, the PSB also approved a previous settlement that we reached with the Conservation Law Foundation, a regional environmental advocacy organization. That settlement included: 1) implementing automated metering infrastructure, which we refer to as CVPS SmartPower™, as quickly as we reasonably can under a timetable to be approved by the PSB; 2) introducing demand response programs for all customer classes; 3) advancing Vermont-based renewable power generation; and 4) working with the DPS and Vermont Energy Efficiency Utility ("EEU"), which is charged with implementing energy efficiency programs throughout Vermont, to develop and implement an EEU program to promote installation of efficient heating systems such as solar thermal hot-water systems, small combined-heat and-power systems and cost-effective heat pumps.

On October 10, 2008, we filed a Motion for Reconsideration and Clarification with the PSB requesting clarification and amendments to certain portions of its order that created uncertainty and had the potential to create significant disputes in the administration of our plan. On October 15, 2008, the DPS filed its response to our motion. On October 23, 2008, the PSB issued a favorable order on our motion. The PSB clarified that, among other things, the quarterly power adjustments and annual earnings sharing adjustments will commence on January 1, 2009 with the first power adjustment filing due on May 1, 2009, for effect on July 1, 2009.

On October 31, 2008, we filed a revised and restated alternative regulation plan incorporating the provisions in the PSB orders. We also submitted a base rate filing for the rate year commencing January 1, 2009 that reflected a 0.33 percent increase in retail rates. The result of the return on equity adjustment for 2009, in accordance with the plan, was a reduction of 0.44 percent, resulting in an allowed return on equity for 2009 of 9.77 percent. On November 17, 2008, the DPS filed a request for suspension and investigation of our filing. Citing concerns about staffing levels and inadequate supporting documentation for some proposed plant additions, the DPS recommended a 0.43 percent rate decrease. On November 25, 2008, the PSB issued an order allowing our rate increase request of 0.33 percent effective January 1, 2009, and also opened an investigation to determine whether the 2009 rates are just and reasonable.

On December 17, 2008, we filed with the PSB a Memorandum of Understanding setting forth agreements that we reached with the DPS regarding the PSB's investigation into our 2009 retail rates. Pursuant to the Memorandum of Understanding, we agreed to leave rates unchanged, with no increase or decrease, and that we and the DPS would request the PSB to open a docket to resolve the DPS's concerns regarding our level of staffing. On February 13, 2009, the PSB approved the Memorandum of Understanding, ordered the rate investigation closed, and opened a docket to investigate our staffing levels. The outcome of the staffing level investigation cannot be predicted at this time.

On February 2, 2009, we filed a motion with the PSB to recover through our alternative regulation plan approximately $4.1 million of extraordinary storm costs incurred in December 2008. On February 3, 2009, the DPS filed a letter supporting our motion. On February 12, 2009, the PSB approved the request. Accordingly, the December 2008 storm cost recovery and amortization will begin on July 1, 2009.

Our retail rates at December 31, 2007 were based on a December 7, 2006 PSB order approving, among other things, a 4.07 percent rate increase effective January 1, 2007 and an allowed rate of return on common equity of 10.75 percent capped until our next rate proceeding. The return on our regulated business did not exceed the allowed return for 2007. At the time the order was issued, we had a pending accounting order request for recovery of $1.5 million of incremental replacement power costs subject to PSB approval. On January 12, 2007, the PSB denied our accounting order request. This outcome had no 2006 income statement impact since the incremental replacement power costs were previously expensed in 2005, and it did not change the 4.07 percent rate increase effective January 1, 2007. Pursuant to the December 2006 order, we deferred $0.8 million of revenue, which was returned to customers, over a 12-month period, in the new rates effective February 1, 2008.

Our retail rates for 2006 were based on a March 29, 2005 PSB order that provided for a 2.75 percent rate decrease and an allowed rate of return on common equity capped at 10.0 percent.

Regulatory Accounting Under SFAS 71, we account for certain transactions in accordance with permitted regulatory treatment whereby regulators may permit incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when recovered through future revenues. In the event that we no longer meet the criteria under SFAS 71 and there is not a rate mechanism to recover these costs, we would be required to write off $16.6 million of regulatory assets (total regulatory assets of $63.5 million less pension and postretirement medical costs of $46.9 million), $10 million of other deferred charges - regulatory and $17.7 million of other deferred credits - regulatory. This would result in a total extraordinary charge to operations of $8.9 million on a pre-tax basis as of December 31, 2008. We would be required to record pre-tax pension and postretirement costs of $46 million to Accumulated Other Comprehensive Loss and $0.9 million to Retained Earnings as reductions to stockholders' equity. We would also be required to determine any potential impairment to the carrying costs of deregulated plant. Regulatory assets, certain other deferred charges and other deferred credits are shown in the table below (dollars in thousands).

	2008	2007
Regulatory assets		
Pension and postretirement medical costs - SFAS 158	**$ 46,911**	$ 14,673
Nuclear plant dismantling costs	**10,049**	11,889
Nuclear refueling outage costs - Millstone Unit #3	**1,347**	820
Income taxes	**4,115**	3,757
Asset retirement obligations and other	**1,052**	849
Total Regulatory assets	**63,474**	31,988
Other deferred charges - regulatory		
Vermont Yankee sale costs (tax)	**673**	673
Deferral of December 2008 storm costs	**4,059**	0
Unrealized losses on power-related derivatives	**4,070**	7,817
Other	**1,178**	498
Total Other deferred charges - regulatory	**9,980**	8,988
Other deferred credits - regulatory		
Asset retirement obligation - Millstone Unit #3	**1,497**	3,085
Vermont Yankee related deferrals	**789**	1,596
Emission allowances and renewable energy credits	**308**	616
Unrealized gains on power-related derivatives	**12,756**	707
Environmental remediation	**1,000**	1,834
Other	**1,346**	1,557
Total Other deferred credits - regulatory	**$ 17,696**	$ 9,395

The regulatory assets included in the table above are being recovered in retail rates. 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. 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 Part II, item 8, Note 15 - 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 Part II, item 8, Note 3 - Investments in Affiliates. Power-related derivatives are discussed in more detail in Part II, Item 8, Note 5 - Fair Value.

NOTE 8 - SHARE-BASED COMPENSATION
We have awarded share-based compensation to key employees and non-employee directors under several stock compensation plans. Awards under these plans have been comprised of stock options, common stock and performance shares. The last stock option awards were made in 2006 and we do not anticipate making additional awards. At December 31, 2008 these plans included:

Plan	Shares Authorized	Stock Options Outstanding	Shares Available for Future Grant
1997 Stock Option Plan - Key Employees	350,000	79,458	0
2000 Stock Option Plan - Key Employees	350,000	182,630	0
Omnibus Stock Plan (a)	450,000	116,869	154,863
Total	1,150,000	378,957	154,863

(a) The 2002 Long-Term Incentive Plan was amended in 2008. The amendments renamed the plan as the Central Vermont Public Service Corporation Omnibus Stock Plan ("Omnibus Stock Plan"), added 100,000 additional shares of our common stock to be issued under the plan and revised the plan to conform to certain other regulatory changes. The adoption of the amendments to the plan was authorized by the PSB on April 23, 2008 and by our shareholders on May 6, 2008.

The Omnibus Stock Plan authorizes the granting of stock options, stock appreciation rights, common shares and performance shares. The plan is intended to encourage stock ownership by recipients. Stock options have not been granted as a form of compensation since 2005 and stock appreciation rights have not been granted.

Total share-based compensation expense recognized in the income statement for the last three years was $0.8 million in 2008, $0.6 million in 2007 and $0.9 million in 2006. The total income tax benefit recognized in the income statement for share-based compensation was $0.3 million in 2008, $0.2 million in 2007 and $0.3 million in 2006. No compensation costs were capitalized. Cash received from exercise of stock options was $1 million in 2008, $1.1 million in 2007 and $1.3 million in 2006. The tax benefit realized for the tax deductions from option exercises and performance shares issued in 2008 was $0.4 million. The tax benefit realized for the tax deductions from option exercises was $0.4 million in 2007 and $0.1 million in 2006. These amounts are included in other paid in capital on the balance sheet.

Currently, stock options that are exercised and other stock awards are settled from authorized but unissued common shares. Under the existing plans, they may also be settled by the issuance of treasury shares or through open market purchases of common shares. Awards other than stock options can also be settled in cash at the discretion of the Compensation Committee of our Board of Directors. Historically, these awards have not been settled in cash.

Stock Options All outstanding stock options were granted at the fair market value of the common shares on the date of grant, and vested immediately. The maximum term of options is five years for non-employee directors and 10 years for key employees. Stock option activity during 2008 follows:

	Shares	Weighted Average Exercise Price
Options outstanding and exercisable at January 1	446,007	$ 17.23
Exercised	(67,050)	$ 15.40
Granted	0	$ 0.00
Forfeited	0	$ 0.00
Expired	0	$ 0.00
Options outstanding and exercisable at December 31	378,957	$ 17.55

The total intrinsic value of stock options exercised during the last three years was $0.6 million in 2008, $1 million in 2007, and $0.3 million in 2006. The aggregate intrinsic value of options outstanding and exercisable as of December 31, 2008 was $2.4 million. The weighted-average remaining contractual life for options outstanding and exercisable as of December 31, 2008 was 3.9 years.

Common and Nonvested Shares The fair value of common stock granted to key employees and non-employee directors is equal to the market value of the underlying common stock on the date of grant. The shares vest immediately or cliff vest over predefined service periods. Although full ownership of the shares does not transfer to the recipients until vested, the recipients have the right to vote the shares and to receive dividends from the date of grant. A summary of common and nonvested share activity during 2008 follows:

	Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1	1,000	$ 18.15
Granted	10,376	$ 21.18
Vested	(3,891)	$ 21.18
Deferred	(6,485)	$ 21.18
Forfeited	0	$ 0.00
Nonvested at December 31	1,000	$ 18.15

In 2008, common stock was granted as part of the Board of Directors' annual retainer. These shares vest immediately, however, individual directors can elect to defer receipt of their retainer under the terms of the Deferred Compensation Plan for Directors and Officers. The fair value of shares vested in 2008 totaled approximately $0.1 million. Compensation expense was $0.2 million in 2008, $0.3 million in 2007 and $0.4 million in 2006. Unearned compensation expense at December 31, 2008 was of a nominal amount.

The weighted-average grant-date fair value of shares granted during 2007 was $32.22 per share and the fair value of shares vested totaled $0.2 million. The weighted-average grant-date fair value of shares granted during 2006 was $21.42 per share and the fair value of shares vested totaled $0.4 million.

Performance Shares The executive officer long-term incentive program is delivered in the form of contingently granted performance shares of common stock. At the start of each year a fixed number of performance shares are contingently granted for three-year service periods (referred to as performance cycles). The number of shares awarded at the end of each performance cycle is dependent on our performance compared to pre-established performance targets for relative Total Shareholder Return ("TSR") compared to all publicly traded electric and combined utilities, and on operational measures. The number of shares awarded at the end of the performance cycles ranges from zero to 1.5 times the number of shares targeted, based on actual performance versus targets. Dividends payable on performance shares during the performance cycle are reinvested into additional performance shares. Once the award is earned, shares become fully vested. If the participant's employment is terminated mid-cycle due to retirement, death, disability or a change-in-control, that employee or their estate is entitled to receive a pro rata portion of shares at target performance.

The fair value of performance shares for operational measures was estimated based on the market value of the shares on the grant date and the expected outcome of each measure. The grant-date fair value of performance shares with operational measures granted in 2008 was $30.40 per share. Compensation cost is recognized over the three-year performance cycle and is adjusted for the actual percentage of target achieved.

The fair value of performance shares for TSR measures was estimated on the grant date using a Monte Carlo simulation model. The grant-date fair value of performance shares with TSR measures granted in 2008 was $28.00 per share. Compensation cost is recognized on a straight-line basis over the three-year performance cycle and is not adjusted for the actual percentage of target achieved. The weighted-average assumptions used in the Monte Carlo valuation for TSR performance shares granted during the past three years are shown in the table below.

	2008	2007
Volatility	**32.20%**	25.97%
Risk-free rate of return	**2.76%**	4.68%
Dividend yield	**3.08%**	4.04%
Term (years)	**3**	3

The volatility assumption was based on the historical volatility of our common stock over the three-year period ending on the grant date. The risk-free rate of return was based on the yield, at the grant date, of a U.S. Treasury security with a maturity period of three years. The dividend yield assumption was based on historical dividend payouts. The expected term of performance shares is based on a three-year cycle.

A summary of performance share activity, excluding estimated dividend equivalents, during 2008 follows:

	Shares	Weighted Average Grant-Date Fair Value
Outstanding at January 1	62,400	$ 19.47
Contingently granted for the 2008 - 2010 performance cycle	21,700	$ 29.20
Vested for the 2006 - 2008 performance cycle (a)	(33,800)	$ 17.50
Forfeited	0	$ 0.00
Outstanding at December 31	50,300	$ 25.00

a) Based on 100 percent performance level.

Compensation expense for performance share plans amounted to $0.6 million in 2008, $0.3 million in 2007 and $0.5 million in 2006.

Unrecognized compensation expense for outstanding performance shares based on anticipated performance levels as of December 31, 2008 is approximately $0.5 million and is expected to be recognized over 1.5 years.

At December 31, 2008, the fair value of performance shares that were earned or vested, including dividend equivalents, based on goals that were achieved for the 2006 - 2008 performance cycle and were pending Board of Director approval, was $0.9 million.

In the first quarter of 2008, a total of 22,701 common shares were issued for the 2005 - 2007 performance cycle, of which the participants withheld receipt of 7,612 shares to satisfy withholding tax obligations. The fair value of shares vested at December 31, 2007 was $0.7 million based on the goals that were achieved for the 2005 - 2007 performance cycle.

NOTE 9 - COMMON STOCK

On November 18, 2008, we entered into an underwriting agreement with a financial institution. Pursuant to the agreement, we agreed to sell 1,190,000 shares of our common stock ($6 par value per share), plus an additional 119,000 shares should the underwriters exercise their 30-day option to cover over-allotments, if any. The shares were sold to the underwriters at a net price of $17.86 per share for sale to the public at a price of $19.00 per share. On November 24, 2008, we issued 1,190,000 shares, resulting in net proceeds of approximately $21.3 million. No additional shares were issued to the underwriters as there were no over-allotments. The net proceeds of the offering were used for general corporate purposes, including the repayment of debt, capital expenditures, investments in Transco and working capital requirements.

NOTE 10 - TREASURY STOCK

Treasury stock is recorded at the average cost of $22.75 per share, including additional costs, and results in a reduction of shareholders' equity on the Consolidated Balance Sheet. In April 2006, we purchased 2,249,975 shares of our common stock at $22.50 per share using proceeds from the December 20, 2005 sale of Catamount. In July 2007, we began using Treasury shares to meet reinvestment needs under the Dividend Reinvestment Plan.

NOTE 11 - PREFERRED AND PREFERENCE STOCK NOT SUBJECT TO MANDATORY REDEMPTION

Preferred and preference stock not subject to mandatory redemption at December 31 consisted of the following (dollars in thousands):

	2008	2007
Preferred stock, $100 par value, outstanding:		
4.150% Series; 37,856 shares	**$ 3,786**	$ 3,786
4.650% Series; 10,000 shares	**1,000**	1,000
4.750% Series; 17,682 shares	**1,768**	1,768
5.375% Series; 15,000 shares	**1,500**	1,500
Total preferred and preference stock not subject to mandatory redemption	**$ 8,054**	$ 8,054

There are 500,000 shares authorized of the Preferred Stock, $100 Par Value class that can be issued with or without mandatory redemption requirements. At December 31, 2008, a total of 100,538 shares were outstanding, including 80,538 that are not subject to mandatory redemption and are listed in the table above, and 20,000 that are subject to mandatory redemption and described in Note 12 - Preferred Stock Subject to Mandatory Redemption. None of the outstanding Preferred Stock, $100 Par Value, is convertible into shares of any other class or series of our capital stock or any other security.

There are 1,000,000 shares authorized of Preferred Stock, $25 Par Value, and 1,000,000 shares authorized of Preference Stock, $1 Par Value. None of the shares are subject to mandatory redemption. There were none outstanding, issued or redeemed in 2008, 2007 or 2006.

All series of the Preferred Stock, $100 Par Value class are of equal ranking, including those subject to mandatory redemption. Each series is entitled to a liquidation preference over the holders of common stock that is equal to Par Value, plus accrued and unpaid dividends, and a premium if liquidation is voluntary. In general, there are no “deemed” liquidation events. Holders of the Preferred Stock have no voting rights, except as required by Vermont law, and except that if accrued dividends on any shares of Preferred Stock have not been paid for more than two full quarters, each share will have the same voting power as Common Stock. If accrued dividends have not been paid for four or more full quarters, the holders of the Preferred Stock have the right to elect a majority of our Board of Directors. There are no dividends in arrears for preferred stock not subject to mandatory redemption.

All series of Preferred Stock are currently subject to redemption and retirement at our option upon vote of at least three-quarters of our Board of Directors in accordance with the specific terms for each series and upon payment of the Par Value, accrued dividends and a premium to which each would be entitled in the event of voluntary liquidation, dissolution or winding up of our affairs. At December 31, 2008, premiums payable on each series of non-redeemable preferred stock if such an event were to occur are as follows:

Preferred and Preference Stock	Premiums Per Share
4.150% Series	$5.500
4.650% Series	$5.000
4.750% Series	$1.000
5.375% Series	$5.000

NOTE 12 - PREFERRED STOCK SUBJECT TO MANDATORY REDEMPTION

We have one series of Preferred Stock, $100 Par Value that is subject to mandatory redemption, 8.3 Percent Series Preferred Stock, with shares outstanding of 20,000 at December 31, 2008, 30,000 at December 31, 2007 and 40,000 at December 31, 2006. All of the provisions described in Note 11 - Preferred and Preference Stock Not Subject to Mandatory Redemption are the same for the 8.3 Percent Series Preferred Stock, except that at December 31, 2008, the premium payable in the event of voluntary liquidation, dissolution or winding up of our affairs was at $1.66 per share. There are no dividends in arrears for the 8.3 Percent Series Preferred Stock.

The mandatory redemption requirement for the 8.3 Percent Series Preferred Stock is $1 million (10,000 shares at par value) per annum. We may, at our option, also redeem at par an additional non-cumulative $1 million annually. We are scheduled to make annual payments of $1 million in 2009 and 2010 under the mandatory redemption requirements. Thereafter the 8.3 Percent Series Preferred Stock will be fully redeemed. In the fourth quarter of 2008 and 2007, we paid our transfer agent $1 million for the mandatory redemption payment that is effective January 1. The payments to the transfer agent are included in Special Deposits on the Consolidated Balance Sheets.

Dividends paid on preferred stock subject to mandatory redemption are included in Other interest on the Consolidated Statements of Income, and amounted to $0.2 million in 2008, $0.2 million in 2007 and $0.3 million in 2006.

NOTE 13 - LONG-TERM DEBT

Long-term debt at December 31 consisted of the following (dollars in thousands):

	December 31, 2008	December 31, 2007
First Mortgage Bonds		
6.27%, Series NN, due 2008	**$ 0**	$ 3,000
5.00%, Series SS, due 2011	**20,000**	20,000
5.72%, Series TT, due 2019	**55,000**	55,000
6.90%, Series OO, due 2023	**17,500**	17,500
6.83%, Series UU, due 2028	**60,000**	0
8.91%, Series JJ, due 2031	**15,000**	15,000
Revenue Bonds		
New Hampshire Industrial Development Authority Bonds		
3.75%, due 2009	**5,450**	5,450
Total long-term debt	**172,950**	115,950
Less current amount payable, due within one year	**(5,450)**	(3,000)
Total long-term debt less current portion	**$ 167,500**	$ 112,950

First Mortgage Bonds: On May 15, 2008, we issued $60 million of our First Mortgage 6.83% Bonds, Series UU due May 15, 2028. The issuance was pursuant to our Indenture of Mortgage dated as of October 1, 1929, as amended and supplemented by supplemental indentures, including the Forty-Sixth Supplemental Indenture, dated May 1, 2008. The Bonds were issued in a private placement in reliance on exemptions from registration under the Securities Act of 1933, as amended, pursuant to the terms of a Bond Purchase Agreement, dated May 15, 2008, among us and 10 institutional investors. The bond issuance required prior approval by the PSB, which we received on April 23, 2008. We used the proceeds of this offering to repay a $53 million short-term note and for other general corporate purposes.

Substantially all of our utility property and plant is subject to liens under our First Mortgage Bond indenture. The First Mortgage Bonds are callable at our option at any time upon payment of a make-whole premium, calculated as the excess of the present value of the remaining scheduled payments to bondholders, discounted at a rate that is 0.5 percent higher than the comparable U.S. Treasury Bond yield, over the early redemption amount.

The New Hampshire Industrial Development Authority Bonds are pollution control revenue bonds that carry an interest reset provision. These bonds are callable at our option or the bondholders' option on the rate reset date. The final rate reset occurred December 1, 2004. As of December 31, 2008, the bonds are only callable at our option in special circumstances involving unenforceability of the indenture or a change in the usability of the project.

Our debt financing documents do not contain cross-default provisions to affiliates outside of the consolidated entity. Certain of our debt financing documents contain cross-default provisions to our wholly owned subsidiaries, East Barnet, C.V. Realty, Inc. and Custom Investment Corporation. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, inappropriate affiliate transactions or the levy of significant judgments or attachments against our property. Currently, we are not in default under any of our debt financing documents. Scheduled sinking fund payments and maturities for the next five years are $5.5 million in 2009, $0 in 2010, $20.0 million in 2011, $0 in 2012 and $0 in 2013.

Letters of credit: We have three outstanding secured letters of credit, issued by one bank, totaling $16.9 million in support of three separate issues of industrial development revenue bonds totaling $16.3 million, of which $5.5 million is included in Current portion of long-term debt and $10.8 million is included in Notes Payable. We pay an annual fee of 0.9 percent on the letters of credit, based on our secured long-term debt rating. These letters of credit expire on November 30, 2009. The letters of credit contain cross-default provisions to East Barnet, a wholly owned subsidiary. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, the levy of significant judgments, insolvency or violations under ERISA benefit plans. At December 31, 2008, there were no amounts drawn under these letters of credit.

Covenants: Our long-term debt indentures, letters of credit, credit facility and material agreements contain financial covenants. The most restrictive financial covenants include maximum debt to total capitalization of 65 percent, and minimum interest coverage of 2.0 times. At December 31, 2008, we were in compliance with all financial covenants related to our various debt agreements, articles of association, letters of credit, credit facility and material agreements. A significant reduction in future earnings or a significant reduction to common equity could restrict the payment of common and preferred dividends or could cause us to violate our maintenance covenants. If we were to default on our covenant, the lenders could take such actions as terminate their obligations, declare all amounts outstanding or due immediately payable, or take possession of or foreclose on mortgaged property.

Dividend and Optional Stock Redemption Restrictions: Our $40 million revolving credit facility described in Note 14 - Notes Payable and Credit Facility restricts optional redemptions of capital stock and other restricted payments as defined. The First Mortgage Bond indenture and our Articles of Association also contain certain restrictions on the payment of cash dividends on and optional redemptions of all capital stock. Under the most restrictive of these provisions, $64.1 million of retained earnings was not subject to such restriction at December 31, 2008. The Articles also restrict the payment of common dividends or purchase of any common shares if the common equity level falls below 25 percent of total capital, applicable only as long as Preferred Stock is outstanding. Our Articles of Association also contain a covenant that requires us to maintain a minimum common equity level of about $3.3 million as long as any Preferred Stock is outstanding.

NOTE 14 - NOTES PAYABLE AND CREDIT FACILITY

Notes payable at December 31 consisted of the following (dollars in thousands):

		December 31, 2008		December 31, 2007
Revenue Bonds				
Vermont Industrial Development Authority Bonds				
Variable, due 2013 (0.85 % at December 31, 2008 and 3.05% at December 31, 2007)	**$**	**5,800**	$	5,800
Connecticut Development Authority Bonds				
Variable, due 2015 (1.0% at December 31, 2008 and 3.55% at December 31, 2007)		**5,000**		5,000
Short-term note payable				
Variable, due June 30, 2008 (5.44% at December 31, 2007)		**0**		53,000
Total Notes Payable	**$**	**10,800**	$	63,800

Notes Payable: The revenue bonds are floating rate, monthly demand pollution-control bonds. There are no interim sinking fund payments due prior to their maturity. The interest rates reset monthly. Both series are callable at par as follows: 1) at our option or bondholders' option on each monthly interest payment date; or 2) at the option of the bondholders on any business day. There is a remarketing feature if the bonds are put for redemption. Historically, these bonds have been remarketed in the secondary bond market. We have outstanding secured short-term letters of credit that support these bonds, as described in Part II, Item 8, Note 13 - Long-Term Debt.

Short-term Note: At December 31, 2007 we had a six-month unsecured term note in the principal amount of $53.0 million with a major lending institution. On May 15, 2008, we used the proceeds from the issuance of First Mortgage Bonds as described in Part II, Item 8, Note 13 - Long-Term Debt to repay this note in full.

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. It contains financial and non-financial covenants as discussed in Part II, Item 8, Note 13 - Long-Term Debt. 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. Financing terms and costs include an annual commitment fee of 0.225 percent on the unused balance, plus interest on the outstanding balance of amounts borrowed at various interest options and a commission of 0.9 percent on the average daily amount of letters of credit outstanding, all based on our unsecured long-term debt credit rating. Terms also include the requirement to collateralize any outstanding letters of credit in the event of a default under the credit facility. The facility contains a Material Adverse Effect ("MAE") clause (a standard that requires greater adversity than a Material Adverse Change clause). This clause is in effect only when our credit rating is below investment grade; therefore, it is currently in effect. The MAE clause could allow the lending institution to deny a transaction under the credit facility at the point of request. The credit facility also contains cross-default provisions to any of our subsidiaries. These cross-default provisions generally relate to an inability to pay debt or debt acceleration, the levy of significant judgments or voluntary or involuntary liquidation, reorganization or bankruptcy. At December 31, 2008 no amounts were outstanding under this facility.

NOTE 15 - PENSION AND POSTRETIREMENT MEDICAL BENEFITS

We have a qualified, non-contributory, defined-benefit, trusteed pension plan ("Pension Plan") covering all union and non-union employees. Under the terms of the Pension Plan, employees are vested after completing five years of service, and can retire when they are at least age 55 with a minimum of 10 years of service. They are eligible to receive monthly benefits or a lump sum amount. Our funding policy is to contribute an amount equal to the annual actuarial cost or at least a statutory minimum to a trust. We are not required by our union contract to contribute to multi-employer plans. At the end of 2008, we adopted the Fully Generational mortality table. This replaces the RP-2000 mortality table.

We also sponsor a defined-benefit postretirement medical plan that covers all employees who retire with 10 or more years of service after age 45 and who are at least age 55. We fund this obligation through a Voluntary Employees' Benefit Association and 401(h) Subaccount in the Pension Plan. Retirees under the age of 65 ("pre-age 65") participate in plan options similar to active employees. Retirees at or over the age of 65 ("post-age 65") receive limited coverage with a $10,000 annual individual maximum. Company contributions to retiree medical are capped for employees retiring after 1995 at $0.3 million per year for pre-age 65 retirees and are capped at a nominal amount for post-age 65 retirees. There are no retiree contributions for pre-1996 retirees.

Beginning in 2009 the postretirement benefit is being enhanced with sharing of the Medicare Part D subsidy with retirees for whom the company contributions are capped. Under this enhancement, we will split the subsidy evenly between the pre-age 65 and post-age 65 retirees.

As part of our contract with the IBEW Local 300 in December 2008, the parties agreed, subject to ratification by the Board of Directors, to close the pension plan to employees hired after a future date to be determined (the "conversion date"). Employees hired after the conversion date will be given, in addition to the existing match on 401(k) contributions, a core 401(k) contribution of 3 percent of base pay. For employees hired before the conversion date, the current pension benefits will remain in effect. We also plan to enhance the pension benefit by offering the so-called "Rule of 85." Under the Rule of 85, if an employee is at least 55 years old with 10 years of service and their combined service and age totals at least 85, they will be eligible for an unreduced pension benefit.

SFAS No. 158 requires an employer with a defined benefit plan or other postretirement plan to recognize an asset or liability on its balance sheet for the overfunded or underfunded status of the plan. For pension plans, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For postretirement benefit plans, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. The adoption of SFAS No. 158 required us to change the measurement of our plan assets from September 30 to December 31.

Benefit Obligation The changes in benefit obligation for pension and postretirement medical benefits at the December 31, 2008 and September 30, 2007 measurement dates follow (dollars in thousands):

	Pension Benefits		**Postretirement Medical Benefits**	
	2008	2007	**2008**	2007
Benefit obligation at beginning of measurement date	**$ 96,050**	$ 103,853	**$ 26,520**	$ 26,276
Effect of eliminating early measurement date	**884**	0	**66**	0
Service cost	**3,291**	3,552	**621**	577
Interest cost	**6,093**	6,242	**1,611**	1,507
Plan participants' contributions	**0**	0	**1,057**	987
Actuarial loss (gain)	**4,318**	(11,048)	**(951)**	(33)
Gross benefits paid	**(4,400)**	(6,549)	**(2,501)**	(2,993)
less: federal subsidy on benefits paid	**0**	0	**230**	199
Plan amendments	**0**	0	**1,900**	0
Projected obligation as of measurement date	**$ 106,236**	$ 96,050	**$ 28,553**	$ 26,520
Accumulated obligation as of measurement date	**$ 87,310**	$ 78,894	**n/a**	n/a

The reduction in our accumulated postretirement benefit obligation due to the impact of the Medicare Part D subsidy is $3.5 million for 2008 and $3 million for 2007.

The present value of future contributions from Postretirement Plan participants was $36.8 million for 2008 and $35.1 million for 2007.

Benefit Obligation Assumptions Weighted-average assumptions used to determine benefit obligations at the December 31 measurement date for 2008 and the September 30 measurement date for 2007 are shown in the table that follows. The selection methodology used in determining discount rates includes portfolios of "Aa" bonds; all are United States issues and non-callable (or callable with make-whole features) and each issue is at least $50 million in par value. The following weighted-average assumptions for pension and postretirement medical benefits were used in determining our related liabilities at December 31:

	Pension Benefits		Postretirement Medical Benefits	
	2008	2007	**2008**	2007
Discount rates	**6.15%**	6.30%	**6.05%**	6.15%
Rate of increase in future compensation levels	**4.25%**	4.25%	**4.25%**	4.25%

For measurement purposes, a 9 percent annual rate of increase in the per capita cost of covered health care benefits was assumed for fiscal 2009, for pre-age 65 and post-age 65 claims costs. The rate is assumed to decrease 0.5 percent each year until 2017 until an ultimate trend rate of 5.0 percent is reached.

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effect (dollars in thousands):

	Increase	Decrease
Effect on postretirement medical benefit obligation as of December 31, 2008	$ 2,347	$ (1,977)
Effect on aggregate service and interest costs	$ 214	$ (174)

Asset Allocation The asset allocations at the measurement date for 2008 and 2007, and the target allocation for 2009, by asset category, are as follows:

	Pension Plan			Postretirement Medical Plan		
	2009 Target	**2008**	2007	**2009 Target**	**2008**	2007
Equity securities	**61%**	44%	68%	**67%**	67%	67%
Debt securities	**39%**	37%	32%	**33%**	33%	33%
Other	**0%**	19%	0%	**0%**	0%	0%
Total	**100%**	100%	100%	**100%**	100%	100%

Investment Strategy Our pension investment policy seeks to achieve sufficient growth to enable the Pension Plan to meet our future benefit obligations to participants, to maintain certain funded ratios and minimize near-term cost volatility. Current guidelines specify generally that 61 percent of plan assets be invested in equity securities and 39 percent of plan assets be invested in debt securities. The debt securities are fixed-income assets that are invested in longer-duration bonds to match changes in plan liabilities. In response to market conditions, our pension trust committee voted to temporarily revise our target allocation in mid-December 2008. We currently expect to return to our target asset allocation above by mid-2009.

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. In early 2007, the plan assets were invested in cash equivalents. Beginning in May 2007, we adopted an asset allocation mix similar to that of the Pension Plan assets.

Change in Plan Assets The changes in Plan assets at the December 31, 2008 and September 30, 2007 measurement dates follow (dollars in thousands):

	Pension Plan		Postretirement Medical Plan	
	2008	2007	**2008**	2007
Fair value of plan assets at beginning of measurement date	**$ 94,356**	$ 86,131	**$ 13,264**	$ 11,526
Effect of eliminating early measurement date	**$ 369**	0	**$ (22)**	0
Actual (loss) return on plan assets	**(14,209)**	10,718	**(5,652)**	605
Employer contributions	**3,062**	4,056	**3,104**	3,139
Plan participants' contributions	**0**	0	**1,057**	987
Gross benefits paid	**(4,400)**	(6,549)	**(2,502)**	(2,993)
Fair value of assets as of measurement date	**$ 79,178**	$ 94,356	**$ 9,249**	$ 13,264

Funded Status The Plans' funded status at December 31 was as follows (dollars in thousands):

	Pension Plan		Postretirement Medical Plan	
	2008	2007	**2008**	2007
Fair value of assets	**$ 79,178**	$ 94,356	**$ 9,249**	$ 13,264
Benefit obligation	**(106,236)**	(96,050)	**(28,553)**	(26,520)
CVPS contributions between measurement and year-end dates	**0**	0	**0**	153
Funded Status	**$ (27,058)**	$ (1,694)	**$ (19,304)**	$ (13,103)

The decrease in the Pension Plan funded status of $25.4 million for 2008 versus 2007 resulted from a decrease of $15.2 million in the fair value of assets as shown in the table above, and an increase of $10.2 million in the benefit obligation, primarily due to actuarial losses and actual losses on plan assets as shown in the tables above. The actuarial losses were primarily the result of lower-than-expected returns on plan assets related to the current economic downturn in the equity markets, changes in plan demographics, and changes in actuarial assumptions.

The decrease in the Postretirement Medical Plan funded status of $6.2 million for 2008 versus 2007 resulted from a decrease of $4 million in the fair value of assets as shown in the table above, and an increase of $2.2 million in the benefit obligation, primarily due to the same reasons described above.

Amounts recognized in the Consolidated Balance Sheets Amounts related to accrued benefit costs recognized in our Consolidated Balance Sheets at December 31 consisted of (dollars in thousands):

	Pension Benefits		Postretirement Medical Benefits	
	2008	2007	**2008**	2007
Non-current liability	**$ (27,058)**	**$ (1,694)**	**$ (19,304)**	**$ (13,103)**

At December 31, 2008, the Postretirement Medical Plan non-current liability shown above included an actuarial estimate of $0.3 million related to our Medicare Part D subsidy payments expected in the first quarter of 2009.

Amounts recognized in Regulatory Assets and Accumulated Other Comprehensive Loss ("AOCL") The pre-tax amounts recognized in Regulatory assets and AOCL in our Consolidated Balance Sheet at December 31, 2008 consisted of (dollars in thousands):

	Pension Benefits			Postretirement Medical Benefits		
	Regulatory Asset	**AOCL**	**Total**	**Regulatory Asset**	**AOCL**	**Total**
Net actuarial loss	**$ 24,883**	**$ 76**	**$ 24,959**	**$ 16,074**	**$ 48**	**$ 16,122**
Prior service cost	**2,093**	**6**	**2,099**	**1,894**	**6**	**1,900**
Transition obligation	**0**	**0**	**0**	**957**	**3**	**960**
Net amount recognized	**$ 26,976**	**$ 82**	**$ 27,058**	**$ 18,925**	**$ 57**	**$ 18,982**

The pre-tax amounts recognized in Regulatory assets and AOCL in our Consolidated Balance Sheet at December 31, 2007 consisted of (dollars in thousands):

	Pension Benefits			Postretirement Medical Benefits		
	Regulatory Asset	AOCL	Total	Regulatory Asset	AOCL	Total
Net actuarial loss	$ (888)	$ (3)	$ (891)	$ 11,622	$ 35	$ 11,657
Prior service cost	2,577	8	2,585	1	0	1
Transition obligation	0	0	0	1,275	4	1,279
Net amount recognized	$ 1,689	$ 5	$ 1,694	$ 12,898	$ 39	$ 12,937

Changes in Plan Assets and Benefit Obligations Recognized in Regulatory Assets and Other Comprehensive Income Components of pre-tax changes were as follows (dollars in thousands):

	Pension Benefits			Postretirement Medical Benefits		
	Regulatory Asset	AOCL	Total	Regulatory Asset	AOCL	Total
Current year actuarial (gain)/loss	$ 25,773	$ 78	$ 25,851	$ 5,763	$ 17	$ 5,780
Amortization of actuarial loss	0	0	0	(1,049)	(3)	(1,052)
Current year prior service cost	0	0	0	1,894	6	1,900
Amortization of prior service cost	(388)	(1)	(389)	0	0	0
Amortization of transition obligation	0	0	0	(255)	(1)	(256)
Net amount recognized	$ 25,385	$ 77	$ 25,462	$ 6,353	$ 19	$ 6,372

Net Periodic Benefit Costs Components of net periodic benefit costs were as follows (dollars in thousands):

	Pension Benefits			Postretirement Benefits		
	2008	2007	2006	**2008**	2007	2006
Service cost	**$ 3,291**	$ 3,552	$ 3,686	**$ 621**	$ 578	$ 706
Interest cost	**6,092**	6,242	5,971	**1,611**	1,507	1,695
Expected return on plan assets	**(7,323)**	(6,719)	(5,744)	**(1,067)**	(932)	(716)
Amortization of net actuarial loss	**0**	582	785	**1,052**	1,051	1,591
Amortization of prior service cost	**389**	399	401	**0**	0	1
Amortization of transition obligation	**0**	0	0	**256**	256	256
Net periodic benefit cost	**2,449**	4,056	5,099	**2,473**	2,460	3,533
Less amounts capitalized	**405**	693	885	**409**	420	613
Net benefit costs expensed	**$ 2,044**	$ 3,363	$ 4,214	**$ 2,064**	$ 2,040	$ 2,920

Benefit Cost Assumptions Weighted average assumptions are used in determining our annual benefit costs. The weighted average assumptions shown for each year in the table below were set at September 30 the previous year.

	Pension Benefits			Postretirement Medical Benefits		
	2008	2007	2006	**2008**	2007	2006
Weighted-average discount rates	**6.30%**	5.95%	5.65%	**6.15%**	5.80%	5.65%
Expected long-term return on assets	**8.25%**	8.25%	8.25%	**8.25%**	8.25%	8.25%
Rate of increase in future compensation levels	**4.25%**	4.25%	4.00%	**4.25%**	4.25%	4.00%

2009 Cost Amortizations: The estimated amounts that will be amortized from regulatory assets and accumulated other comprehensive income into net periodic benefit cost in 2009 are as follows (dollars in thousands):

	Pension Benefits	Postretirement Medical Benefits
Actuarial loss	$ 0	$ 1,570
Prior service cost	351	225
Transition benefit obligation	0	256
Total	$ 351	$ 2,051

Expected Long-Term Rate of Return on Plan Assets The expected long-term rate of return on assets shown in the table above was used to calculate the 2008 pension and postretirement medical benefit expenses. The expected long-term rate of return on assets used to calculate these expenses for 2009 will be 7.85 percent.

In formulating the assumed rate of return, we considered historical returns by asset category and expectations for future returns by asset category based, in part, on simulated capital market performance over the next 10 years.

In 2008 the Pension Plan assets realized a loss of 12.2 percent, net of fees, due to historic underperformance in global financial markets. The Pension Plan assets earned a rate of return of 12.8 percent for the Plan year ended September 30, 2007 and 8.2 percent for the Plan year ended September 30, 2006.

Trust Fund Contributions The Pension Plan currently meets the minimum funding requirements of the Employee Retirement Income Security Act of 1974. In June 2008, we contributed $3.1 million to both the pension and postretirement medical trust funds.

Expected Cash Flows The table below reflects the total benefits expected to be paid from the external Pension Plan trust fund or from our assets, including both our share of the pension and postretirement benefit costs and the share of the postretirement medical benefit cost funded by participant contributions. Expected contributions reflect amounts expected to be contributed to funded plans. Of the benefits expected to be paid in 2009, approximately $8.3 million will be paid from the Pension Plan trust fund, and $2.3 million will be paid from the postretirement medical trust funds to reimburse us for out-of-pocket benefit payments. Information about the expected cash flows for the Pension Plan and postretirement medical benefit plans is as follows (dollars in thousands):

	Pension Benefits	Postretirement Medical Benefits	
		Gross	Expected Federal Subsidy
Employer Contributions			
2009	$ 3,000	$ 3,700	
Expected Benefit Payments			
2009	$ 8,350	$ 2,258	$ 253
2010	$ 7,811	$ 2,348	$ 282
2011	$ 7,460	$ 2,416	$ 310
2012	$ 10,726	$ 2,465	$ 341
2013	$ 7,766	$ 2,570	$ 368
2014 – 2018	$ 46,623	$ 13,609	$ 2,309

As of December 31, 2008, the Medicare Part D subsidy reduced the postretirement benefit obligation by $3.5 million and reduced the 2008 net periodic benefit cost by $0.4 million. The estimated Medicare Part D subsidy included in the expected gross postretirement medical benefit payments is shown above.

Other

Long-term Disability We record nonaccumulating post-employment long-term disability benefits in accordance with SFAS 5. For 2008, the year-end post-employment medical benefit obligation was $1.6 million, of which $1.5 million was recorded as Accrued pension and medical benefit obligations and $0.1 million was recorded as Other current liabilities. The 2007 year-end post-employment medical benefit obligation was $1.6 million, of which $1.5 million was recorded as Accrued pension and medical benefit obligations and $0.2 million was recorded as Other current liabilities. The pre-tax post-employment benefit costs charged to expense, including insurance premiums, were $0.1 million in 2008, $0.2 million in 2007 and $0.6 million in 2006.

401(k) Savings Plan Most eligible employees choose to participate in our 401(k) Savings Plan. This savings plan provides for employee pre-tax and post-tax contributions up to specified limits. We match employee pre-tax contributions after one year of service. On January 1, 2007, the match increased from a maximum of 4.0 percent to a maximum of 4.25 percent of eligible compensation. Eligible employees are at all times vested 100 percent in their pre-tax and post-tax contribution account and in their matching employer contribution. Our matching contributions amounted to $1.4 million in 2008, $1.3 million in 2007 and $1.2 million in 2006. As part of our contract with the IBEW Local 300 in December 2008, the parties agreed, subject to ratification by the Board of Directors, to close the pension plan to employees hired after the conversion date. Employees hired after the conversion date will be given, in addition to the existing match on 401(k) contributions, a core 401(k) contribution of 3 percent of base pay.

Other Benefits We also provide an Officers' Supplemental Retirement Plan ("SERP") to certain of our executive officers. The SERP is designed to supplement the retirement benefits available through our qualified Pension Plan.

For 2008, the accumulated year-end SERP benefit obligation, based on the same discount rate described above for pension, was $3.6 million of which $3.3 million was recorded as Accrued pension and benefit obligations and $0.3 million was recorded as Other current liabilities in the Consolidated Balance Sheets. The 2007 accumulated year-end SERP benefit obligation was $3.8 million of which $3.5 million was recorded as Accrued pension and benefit obligations and $0.3 million was recorded as Other current liabilities.

The accumulated SERP benefit obligation included a comprehensive gain of $0.3 million in 2008, $0.2 million in 2007 and $0.3 million in 2006. The pre-tax SERP benefit costs charged to expense totaled $0.3 million in 2008, $0.4 million in 2007 and $0.6 million for 2006. At December 31, 2006, a pre-tax adjustment of $0.8 million was recorded to accumulated other comprehensive income related to adoption of SFAS No. 158. This adjustment included $0.7 million of net losses and $0.1 million of prior service costs.

Benefits are funded through life insurance policies held by a Rabbi Trust. Rabbi Trust assets are not considered plan assets for accounting purposes under SFAS No. 87. The year-end balance included in Investments and Other Assets on our Consolidated Balance Sheets was $5.5 million in 2008 and $7.5 million in 2007. Changes in cash surrender value are included in Other income on our Consolidated Statements of Income. These pre-tax amounts were a decrease of $2.6 million for 2008, a decrease of $0.2 million for 2007 and an increase of $0.2 for 2006.

NOTE 16 - INCOME TAXES

The income tax expense (benefit) from continuing operations as of December 31 consisted of the following (dollars in thousands):

	2008	2007	2006
Federal:			
Current	**$ (6,636)**	$ 2,899	$ 4,875
Deferred	**15,398**	2,566	3,144
Investment tax credits, net	**(379)**	(379)	(379)
Valuation allowance	**(99)**	0	0
	8,284	5,086	7,640
State:			
Current	**519**	1,124	1,311
Deferred	**1,654**	539	1,055
Valuation allowance	**283**	0	0
	2,456	1,663	2,366
Total federal and state income taxes	**$ 10,740**	$ 6,749	$ 10,006
Federal and state income taxes charged to:			
Operating expenses	**$ 4,878**	$ 5,291	$ 8,569
Other income	**5,862**	1,458	1,437
	$ 10,740	$ 6,749	$ 10,006

The reconciliation between income taxes computed by applying the U.S. federal statutory rate and the reported income tax expense (benefit) from continuing operations as of December 31 follows (dollars in thousands):

	2008	2007	2006
Income (loss) before income tax	**$ 27,125**	$ 22,553	$ 28,107
Federal statutory rate	**35.0%**	35.0%	35.0%
Federal statutory tax expense	**9,494**	7,894	9,838
Increase (benefit) in taxes resulting from:			
Dividend received deduction	**(408)**	(647)	(494)
State income taxes net of federal tax benefit	**1,695**	1,106	1,729
Investment credit amortization	**(379)**	(379)	(379)
Renewable Electricity Credit	**(249)**	(275)	(273)
AFUDC equity	**109**	198	194
Life insurance	**680**	(139)	(236)
Medicare Part D	**(157)**	(193)	(107)
Domestic production activities deduction	**0**	(147)	(63)
Valuation allowance	**(99)**	0	0
Change in estimate for tax contingencies	**0**	0	(191)
Other	**54**	(669)	(12)
Total income tax expense	**$ 10,740**	$ 6,749	$ 10,006
Effective combined federal and state income tax rate	39.6%	29.9%	35.6%

As a result of the January 1, 2007 adoption of FIN 48, we decreased previously recorded tax contingencies by $0.6 million. In accordance with FIN 48 adoption guidelines this decrease did not affect the effective tax rate. We decreased estimated tax contingencies by $0.2 million in 2006 due to a reduction in potential tax liabilities.

We increased our estimate of FIN 48 unrecognized tax benefit by $1.9 million in 2007. In accordance with FIN 48 adoption guidelines and the impact of deferred tax accounting, a net decrease in unrecognized tax benefits of less than $0.1 million affected the effective tax rate. During 2008, unrecognized tax benefits were reduced by $0.2 million which, due to the impact of deferred tax accounting had a nominal impact on the effective tax rate.

SFAS No. 109 prohibits the recognition of all or a portion of deferred income tax benefits if it is more likely than not that the deferred tax asset will not be realized. There were no valuation allowances recorded for the periods ended 2007 and 2006. In December 2008, we established a $0.2 million valuation allowance. At issue is the ability to utilize a State of Vermont capital loss carryforward during the five-year carryforward period ending December 31, 2013. At this time we believe it is more likely than not that the capital loss carryforward will expire unused.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31 are presented below (dollars in thousands):

	2008	2007
Deferred tax assets - current		
Reserves for uncollectible accounts	**$ 885**	$ 710
Deferred compensation and pension	**975**	968
Environmental costs accrual	**307**	188
SFAS No. 5 loss accrual	**485**	485
Active Medical Accrual	**379**	337
SFAS No. 133 - derivative instruments	**1**	1,307
Other accruals	**391**	223
Total deferred tax assets - current	**3,423**	4,218
Deferred tax liabilities - current		
Property tax accruals	**304**	265
Prepaid insurance	**382**	315
SFAS No. 133 - derivative instruments	**5,115**	0
Total deferred tax liabilities - current	**5,801**	580
Net deferred tax (liabilities) assets - current	**(2,378)**	3,638
Deferred tax assets - long term		
Equity investments	**0**	1,348
Accruals and other reserves not currently deductible	**1,861**	612
Deferred compensation and pension	**473**	508
Environmental costs accrual	**800**	1,333
Millstone decommissioning costs	**1,703**	2,288
Contributions in aid of construction	**2,111**	2,198
Revenue deferral - Vermont utility earnings	**22**	389
SFAS No. 5 - loss accrual	**2,908**	3,393
SFAS No. 133 - derivative instruments	**6,818**	1,861
SFAS No. 158 - benefit liability	**18,786**	6,204
Long-term disability	**536**	637
Total deferred tax assets - long term	**36,018**	20,771
Less valuation allowance	**(184)**	0
	35,834	20,771
Deferred tax liabilities		
Property, plant and equipment	**44,087**	40,190
Net SFAS No. 109 regulatory asset	**1,668**	1,523
Vermont Yankee sale	**672**	672
SFAS No. 158 - regulatory asset	**19,011**	5,946
SFAS No. 133 - derivative instruments	**1,704**	3,168
Decommissioning costs	**1,312**	1,909
Partnerships	**8,968**	0
Storm Deferral	**1,645**	0
Other	**2,081**	1,029
Total deferred tax liabilities - long term	**81,148**	54,437
Net deferred tax liabilities - long term	**45,314**	33,666
Net deferred tax liabilities	**$ 47,692**	$ 30,028

A summary of the liabilities and assets combining current and long-term:

		2008		2007
Total deferred tax liabilities - current and long-term	**$**	**86,949**	$	55,017
Less total deferred tax assets - current and long-term		**39,257**		24,989
Net deferred tax liabilities	**$**	**47,692**	$	30,028

NOTE 17 - COMMITMENTS AND CONTINGENCIES

Long-Term Power Purchases *Vermont Yankee:* We are purchasing our entitlement share of Vermont Yankee plant output through the PPA between Entergy-Vermont Yankee and VYNPC. One remaining secondary purchaser continues to receive less than 0.5 percent of our entitlement. An uprate in 2006 increased the plant's operating capacity by approximately 20 percent. After completion of the uprate, VYNPC's entitlement to plant output declined from 100 percent to 83 percent, and our entitlement share declined from 35 percent to 29 percent. Therefore our nominal entitlement continues to be approximately 180 MW. Entergy-Vermont Yankee has no obligation to supply energy to VYNPC over its entitlement share of plant output, so we receive reduced amounts when the plant is operating at a reduced level, and no energy when the plant is not operating. The plant normally shuts down for about one month every 18 months for maintenance and to insert new fuel into the reactor. A scheduled refueling outage was completed in November 2008.

Prices under the PPA increase $1 per megawatt-hour each calendar year, from $42 in 2009 to $45 in 2012. The PPA contains a provision known as the "low market adjuster", which calls for a downward adjustment in the contract price if market prices for electricity fall by defined amounts; however, if market prices rise, PPA prices are not adjusted upward in excess of the PPA price. Estimated annual purchases are expected to range from $61 million to $64 million for 2009 through 2011, and $17 million for 2012 when the contract expires in March. A summary of the PPA, including estimated average amounts for 2009 through 2012, is shown in the table below. The total cost estimates are based on projected mWh purchase volumes at PPA rates, plus estimates of VYNPC costs, primarily net interest expense and the cost of capital. Actual amounts may differ.

		2009		**Estimated Average 2010 - 2012**
Average capacity acquired		176 MW		131 MW
Share of VYNPC entitlement		34.83%		34.83%
Annual energy charge per mWh	$	42.07	$	43.83
Average total cost per mWh	$	42.36	$	43.94
Contract period termination				March 2012

We normally purchase replacement energy in the wholesale markets in New England when the Vermont Yankee plant is not operating or is operating at reduced levels. We typically enter into forward purchase contracts for replacement power during scheduled refueling outages, and account for those contracts as derivatives.

In July 2008, the Vermont Yankee plant reduced production levels (also referred to as a derate) for almost 12 days, reaching a low of approximately 17 to 20 percent capacity during some of that time. The derate resulted from issues related to the plant's cooling towers. The incremental costs of the replacement power that we purchased during that time amounted to approximately $1.1 million. We also lost approximately $1.1 million in resale sales revenue during that time. We were able to apply approximately $0.1 million as a reduction in purchased power expense from a regulatory liability established for the difference in the premium we paid for Vermont Yankee forced outage insurance and amounts currently collected in retail rates.

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

We are considering whether to seek recovery of the incremental costs from Entergy-Vermont Yankee under the terms of the PPA based upon the results of a recent NRC inspection, in which the inspection team found that Entergy-Vermont Yankee, among other things, did not have sufficient design documentation available to help it prevent problems with the cooling towers. The NRC released its findings on October 14, 2008. We cannot predict the outcome of this matter at this time.

We have forced outage insurance to cover additional costs, if any, of obtaining replacement power from other sources if the Vermont Yankee plant experiences unplanned outages. The coverage applies to unplanned outages of up to 30 consecutive calendar days per outage event, and provides for payment of the difference between the spot market price and approximately $40/mWh. The aggregate maximum coverage is $12 million. This outage insurance does not apply to derates. In the first quarter of 2008, we renegotiated the policy to extend coverage through March 31, 2009 instead of December 31, 2008. We are currently working with an insurance broker to obtain insurance coverage for the remainder of 2009 through March of 2012 when the contract between Entergy-Vermont Yankee and VYNPC ends.

We were a party to a PSB Docket that was opened in June 2006 to investigate whether the reliability of the increased plant output will be adversely affected by the operation of the plant's steam dryer. In September 2006, the PSB issued an order requiring Entergy-Vermont Yankee to provide additional ratepayer protections. The protection period has expired without occurrence of such an event.

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

If the Vermont Yankee plant is shut down for any reason prior to the end of its operating license, we would lose the economic benefit of an energy volume equal to close to 50 percent of our total committed supply and have to acquire replacement power resources for approximately 40 percent of our estimated power supply needs. Based on projected market prices as of December 31, 2008, the incremental replacement cost of lost power, including capacity, is estimated to average $37.5 million annually. 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 any such shutdown. However, an early shutdown could materially impact our financial position and future results of operations if the costs are not recovered in retail rates in a timely fashion. The Power Cost Adjustment Mechanism within our alternative regulation plan will allow more timely recovery of power costs in 2009, 2010 and 2011.

Hydro-Quebec: We are purchasing power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract. The VJO is a group of Vermont electric companies, municipal utilities and cooperatives, including us. The VJO Power Contract has been in place since 1987 and purchases began in 1990. Related contracts were subsequently negotiated between us and Hydro-Quebec, altering the terms and conditions contained in the original contract by reducing the overall power requirements and related costs. The VJO contract runs through 2020, but our purchases under the contract end in 2016.

Under the VJO Power Contract, the VJO had elections to change the annual load factor from 75 percent to between 70 and 80 percent five times through 2020, while Hydro-Quebec had elections to reduce the load factor to not less than 65 percent three times during the same period. Hydro-Quebec and the VJO have used all of their elections. As of November 1, 2007, the annual load factor is 75 percent for the remainder of the contract, unless the contract is changed or there is a reduction due to the adverse hydraulic conditions described below.

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

There are specific contractual provisions providing that in the event any VJO member fails to meet its obligation under the contract with Hydro-Quebec, the remaining VJO participants, will "step-up" to the defaulting party's share on a pro-rata basis. As of December 31, 2008, our obligation is about 47 percent of the total VJO Power Contract through 2016, which represents approximately $421 million, on a nominal basis.

In accordance with FASB Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* ("FIN 45"), we are required to disclose the "maximum potential amount of future payments (undiscounted) the guarantor could be required to make under the guarantee." Such disclosure is required even if the likelihood is remote. With regard to the "step-up" provision in the VJO Power Contract, we must assume that all members of the VJO simultaneously default in order to estimate the "maximum potential" amount of future payments. We believe this is a highly unlikely scenario given that the majority of VJO members are regulated utilities with regulated cost recovery. Each VJO participant has received regulatory approval to recover the cost of this purchased power in their most recent rate applications. Despite the remote chance that such an event could occur, we estimate that our undiscounted purchase obligation would be about an additional $493 million for the remainder of the contract, assuming that all members of the VJO defaulted by January 1, 2009 and remained in default for the duration of the contract. In such a scenario, we would then own the power and could seek to recover our costs from the defaulting members or our retail customers, or resell the power in the wholesale power markets in New England. The range of outcomes (full cost recovery, potential loss or potential profit) would be highly dependent on Vermont regulation and wholesale market prices at the time.

Total purchases from Hydro Quebec were $63.7 million in 2008, $64.9 million in 2007 and $64.3 million in 2006. A summary of the Hydro-Quebec contract projected charges, for the years indicated, is shown in the table below. Projections are based on certain assumptions including availability of the transmission system and scheduled deliveries, so actual amounts may differ (dollars in thousands, except per kWh amounts):

	Estimated Average	
	2009 - 2012	2013 - 2016
Annual Capacity Acquired	145.2 MW	(a)
Minimum Energy Purchase - annual load factor	75%	75%
Energy Charge	$ 31,617	$ 20,873
Capacity Charge	32,845	20,007
Total Energy and Capacity Charge	$ 64,462	$ 40,880
Average Cost per kWh	$ 0.068	$ 0.071

(a) Annual capacity acquired is projected to average approximately 116 MW for 2013 - 2014, 100 MW for 2015 and 19 MW for 2016.

Independent Power Producers: We receive power from several Independent Power Producers ("IPPs"). These plants use water and biomass as fuel. Most of the power comes through a state-appointed purchasing agent, VEPP Inc., which allocates power to all Vermont utilities under PSB rules. The cost of power purchases from IPPs has been reduced since mid 2003 based on a PSB-approved settlement reached by the DPS, us and other parties. The settlement was related to various legal proceedings and negotiations that began in 1999 to change the IPPs' contracts with VEPP Inc. to reduce power costs for customers' benefit. Our share of the savings is expected to range from $0.3 million to $0.5 million annually for the years 2009 through 2012. In 2008, total purchased power from IPPs amounted to $26.4 million, representing approximately 7 percent of total mWh purchased and 16 percent of total purchased power expense. Total purchased power from IPPs was $22.8 million in 2007 and $24.0 million in 2006. Estimated annual purchases are expected to range from $17.7 million to $19.4 million for the years 2009 through 2012. These estimates are based on assumptions regarding average weather conditions and other factors affecting generating unit output, so actual amounts may differ.

Joint-ownership We have joint-ownership interests in electric generating and transmission facilities that are included in Utility Plant on our Consolidated Balance Sheets. These include:

	Fuel Type	**Ownership**	**Date In Service**	**MW Entitlement**
Wyman #4	Oil	1.78%	1978	10.8
Joseph C. McNeil	Various	20.00%	1984	10.8
Millstone Unit #3	Nuclear	1.73%	1986	21.4
Highgate Transmission Facility		47.52%	1985	N/A

At December 31 our share of these facilities was (dollars in thousands):

	2008			2007		
	Gross Investment	**Accumulated Depreciation**	**Net Investment**	Gross Investment	Accumulated Depreciation	Net Investment
Wyman #4	**$ 3,690**	**$ 2,914**	**$ 776**	$ 3,504	$ 2,817	$ 687
Joseph C. McNeil	**15,857**	**12,291**	**3,566**	15,587	11,762	3,825
Millstone Unit #3	**77,879**	**40,246**	**37,633**	77,349	39,322	38,027
Highgate Transmission Facility	**14,489**	**8,731**	**5,758**	14,390	8,332	6,058
	$ 111,915	**$ 64,182**	**$ 47,733**	$ 110,830	$ 62,233	$ 48,597

Our share of operating expenses for these facilities is included in the corresponding operating accounts on the Consolidated Statements of Income. Each participant in these facilities must provide for its financing.

We have a 1.7303 joint-ownership percentage in Millstone Unit # 3, in which Dominion Nuclear Connecticut ("DNC") is the lead owner with about 93.4707 percent of the plant joint-ownership. In August 2008 the NRC approved a request by DNC to increase the Millstone Unit #3 plant's generating capacity by approximately 7 percent. We are obligated to pay our ownership share of the related costs. The uprate was completed during the scheduled refueling outage that concluded in November 2008 and our share of plant generation increased by 1.4 MW.

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. 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.

Nuclear Decommissioning Obligations We are obligated to pay our share of nuclear decommissioning costs for nuclear plants in which we have an ownership interest. We have an external trust dedicated to funding our joint-ownership share of future decommissioning costs. DNC has suspended contributions to the Millstone Unit #3 Trust Fund because the minimum Nuclear Regulatory Commission ("NRC") funding requirements are being met or exceeded. We have also suspended contributions to the Trust Fund, but could choose to renew funding at our own discretion as long as the minimum requirement is met or exceeded. If a need for additional decommissioning funding 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. Our obligations related to these plants are described in Part II, Item 8, 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. At this time, the fund balance is expected to equal or exceed the obligation. Excess funds, if any, will be returned to us and must be applied to the benefit of retail consumers.

Nuclear Insurance The Price-Anderson Act ("Act") provides a framework for immediate, no-fault insurance coverage for the public in the event of a nuclear power plant accident. The Energy Policy Act of 2005 extended the Act for 20 years. There are two levels of coverage. The primary level provides liability insurance coverage of $300 million. If this amount is not sufficient to cover claims arising from an accident, the second level applies. For the second level, each nuclear plant must pay a premium in arrears equal to its proportionate share of the excess loss, up to a maximum of $100.6 million per reactor per incident, limited to a maximum annual payout of $15 million per reactor. These assessments will be adjusted for inflation. Currently, based on our joint-ownership interest in Millstone Unit #3, we could become liable for about $0.3 million of such maximum assessment per incident per year. Maine Yankee, Connecticut Yankee and Yankee Atomic maintain $100 million in Nuclear Liability Insurance, but have received exemptions from participating in the secondary financial protection program under the Act.

Performance Assurance At December 31, 2008, we had posted $6.9 million of collateral under performance assurance requirements for certain of our power contracts, of which $3.3 million was in cash and $3.6 million was represented by restricted cash.

We are subject to performance assurance requirements through ISO-New England under the Financial Assurance Policy for NEPOOL members. We are required to post collateral for all net purchased power transactions since our credit limit with ISO-New England is zero.

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.

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.

At December 31, 2007, we had posted $0.3 million of cash and a $5.0 million letter of credit under our revolving credit facility for performance assurance requirements through ISO-New England. Restricted cash of $0.1 million was posted for performance assurance requirements through ISO-New York. We were also required to post $1 million in the form of a letter of credit pursuant to wholesale market contract requirements.

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. This practice ended more than 50 years ago. 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. Some operations and activities are inspected and supervised by federal and state authorities, including the Environmental Protection Agency. We believe that we are in compliance with all laws and regulations and have implemented procedures and controls to assess and assure compliance. Corrective action is taken when necessary. Below is a brief discussion of the sites for which we have recorded reserves.

Cleveland Avenue Property: The Cleveland Avenue property in Rutland, Vermont, was used by a predecessor to make gas from coal. Later, we sited various operations there. Due to the existence of coal tar deposits, polychlorinated biphenyl contamination and the potential for off-site migration, we conducted studies in the late 1980s and early 1990s to quantify the potential costs to remediate the site. Investigation at the site has continued, including work with the State of Vermont to develop a mutually acceptable solution. In 2008, we reviewed our reserve for this site based on a 2006 cost estimate of remediation and determined that it was adequate. The liability for site remediation is expected to range from $0.9 million to $2.3 million. As of December 31, 2008, we accrued $1.2 million representing the most likely cost of the remediation effort.

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

Dover, New Hampshire, Manufactured Gas Facility: In 1999, Public Service Company of New Hampshire ("PSNH") contacted us about this site. PSNH alleged that we were partially liable for cleanup, since the site was previously operated by Twin State Gas and Electric, which merged into CVPS on the same day that PSNH bought the facility. In 2002, we reached a settlement with PSNH in which certain liabilities we might have had were assigned to PSNH in return for a cash settlement paid by CVPS based on completion of PSNH's cleanup effort. Our remaining obligation was less than $0.1 million at December 31, 2008.

The reserve for environmental matters described above amounted to $1.7 million as of December 31, 2008 and $1.9 million as of December 31, 2007. The current and long-term portions are included as liabilities on the Consolidated Balance Sheets. The reserve represents our best estimate of the cost to remedy issues at these sites based on available information as of the end of the reporting periods. 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.

Leases and support agreements

Capital Leases: We had obligations under capital leases of $6.1 million at December 31, 2008 and $6.8 million at December 31, 2007. The current and long-term portions are included as liabilities on the Consolidated Balance Sheets, and are offset by Property Under Capital Leases included in Utility plant. We account for capital leases under SFAS No. 13, *Accounting for Leases*. In accordance with SFAS No. 71 and based on our ratemaking treatment, amortizations of leased assets are recorded as operating expenses on the income statement, depending on the nature and function of the leased assets. Of the $6.1 million, $5.7 million is related to the Phase II Hydro-Quebec ("Phase II") transmission facilities and the remaining $0.4 million is related to several five-year office and computing equipment leases.

We participated with other electric utilities in the construction of the Phase II transmission facilities in New England, which were completed at a total initial cost of $487 million. Under a 30-year support agreement relating to participation in the facilities, we agreed to pay our 5.132 percent share of Phase II costs, including capital costs plus the costs of owning and operating the facilities, over a 25-year recovery period that ends in 2015, plus operating and maintenance expenses for the life of the agreement, in exchange for the rights to use a similar share of the available transmission capacity through 2020. Approximately $29.0 million of additional investments have been made to the Phase II transmission facilities since they were initially constructed. All costs under these agreements are recorded as transmission expense in accordance with our ratemaking policies. At December 31, 2008, the $5.7 million unamortized balance was comprised of $19.1 million related to our share of original costs and additional investments, offset by $13.4 million of accumulated amortization.

We also participated with other electric utilities in the construction of the Phase I Hydro-Quebec ("Phase I") transmission facilities in northeastern Vermont and northern New Hampshire, which were completed at a total cost of $140 million. Under the 30-year support agreement relating to participation in the facilities, we were obligated to pay our 4.55 percent share of Phase I capital costs over a 20-year recovery period that ended in 2006, plus operating and maintenance expenses for the life of the agreement, in exchange for the rights to use a similar share of the available transmission capacity through 2016. At December 31, 2008, we had recorded accumulated amortizations of $4.9 million representing our share of the original costs associated with the Phase I transmission facility.

The Phase I and Phase II support agreements provide options for extending the agreements an additional 20 years. Each option must be exercised two years before each agreement terminates, and the transmission facilities for Phase I and Phase II must operate simultaneously for the interconnection to operate, therefore both agreements would need to be extended to be operative. Future annual payments relating to the Phase I and Phase II transmission facilities are expected to decline from $3.1 million in 2009 to $2.2 million in 2016. If we elect to extend both agreements, annual payments are expected to increase during the renewal terms. Approximately $0.6 million of the annual costs are reimbursed to us pursuant to the New England Power Pool Open Access Transmission Tariff.

For the year ended December 31, 2008, imputed interest on capital leases totaled $0.6 million. A summary of minimum lease payments as of December 31, 2008 follows (dollars in thousands).

Year	**Capital Leases**
2009	$ 1,426
2010	1,359
2011	1,235
2012	1,143
2013	1,060
Thereafter	1,649
Future minimum lease payments	7,872
Less: amount representing interest	1,758
Present value of net minimum lease payments	$ 6,114

Operating Leases: Prior to October 24, 2008, we leased our vehicles and related equipment under one operating lease agreement. The individual leases under this agreement were mutually cancelable one year from lease inception. We had the ability to lease vehicles and related equipment up to an aggregate unamortized balance of $13.0 million, of which $8.4 million was outstanding at December 31, 2008 and $9.9 million was outstanding at December 31, 2007.

Under the terms of the vehicle operating lease, we have guaranteed a residual value to the lessor in the event the leased items are sold. The guarantee provides for reimbursement of up to 87 percent of the unamortized value of the lease portfolio. Under the guarantee, if the entire lease portfolio had a fair value of zero at December 31, 2008, we would have been responsible for a maximum reimbursement of $7.3 million. We consider it unlikely that we would need to make a guarantee payment of any significant amount. We had a liability of $0.2 million at December 31, 2008 included in other current liabilities representing our FIN 45 obligation under the guarantee, and this amount is offset by $0.2 million of prepayments.

The lease agreement also contains a contingent rental provision based on the sale proceeds of any equipment being less than the non-guaranteed portion of the base amount because of abuse, damage, extraordinary wear and tear or excessive usage. However, the total amount due to the lessor for any equipment sold will not exceed the unamortized balance of such equipment.

On November 14, 2008, we received notification from the Lessor that this operating lease agreement was being terminated. Under the terms of the lease, we will be required to terminate all agreements under this lease by November 14, 2009 and pay the unamortized value of the equipment upon termination either by purchasing the equipment or through the sale of the equipment to a third party. The estimated unamortized value upon termination is $6.4 million.

On October 24, 2008, we entered into a second operating lease agreement with a different lessor for our vehicles and other related equipment, prior to the termination of our first lease described above. The lease schedules under this agreement are non-cancellable and provide for payment of rent each month. At the end of the lease term, the Lessor is entitled to recover a termination rental adjustment equal to 20 percent of the acquisition cost of the equipment. This payment can be recovered from the company or through disposition of the equipment. In the case of disposition for less than 20 percent of the acquisition cost, our guarantee obligation is limited to 5 percent of the acquisition cost. If the entire lease portfolio had a fair value of zero at December 31, 2008, we would have been responsible for a maximum reimbursement of $2.3 million, which consists of the remaining lease payments and the 5 percent guarantee obligation. We consider it unlikely that we would need to perform under this guarantee. The maximum amount available for lease under this agreement is currently $4 million, of which $2.3 million was outstanding at December 31, 2008.

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

At December 31, 2008, future minimum rental payments required under non-cancelable operating leases are expected to total $2.3 million, consisting of $0.3 million in 2009, $0.4 million in 2010 and in 2011, $0.3 million in 2012 and in 2013 and $0.6 million thereafter.

Total rental expense, which includes pole attachment rents in addition to the operating lease agreements described above, amounted to $6.3 million in 2008, $6.8 million in 2007, and $6.0 million in 2006. These are included in Other operation on the Consolidated Statements of Income.

Reserve for Loss on Power Contract On January 1, 2004, we terminated a long-term power contract with Connecticut Valley Electric Company, a regulated electric utility that was a wholly owned subsidiary of the company. In accordance with the requirements of SFAS No. 5, *Accounting for Contingencies ("SFAS No. 5"),* we recorded a $14.4 million pre-tax loss accrual in the first quarter of 2004 related to the contract termination. The loss accrual represented our best estimate of the difference between expected future sales revenue, in the wholesale market, for the purchased power that was formerly sold to Connecticut Valley Electric Company and the net cost of purchased power obligations. We review this estimate at the end of each reporting period and will increase the reserve if the revised estimate exceeds the recorded loss accrual. The loss accrual is being amortized on a straight-line basis through 2015, the estimated life of the power contracts that were in place to supply power under the contract.

Catamount Indemnifications Under the terms of the agreements with Catamount and Diamond Castle, we agreed to indemnify them, and certain of their respective affiliates, in respect of a breach of certain representations and warranties and covenants, most of which ended June 30, 2007, except certain items that customarily survive indefinitely. Indemnification is subject to a $1.5 million deductible and a $15 million cap, excluding certain customary items. Environmental representations are subject to the deductible and the cap, and such environmental representations for only two of Catamount's underlying energy projects survived beyond June 30, 2007. Our estimated "maximum potential" amount of future payments related to these indemnifications is limited to $15 million. We have not recorded any liability related to these indemnifications since there has been no change in the status.

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.

Appropriated Retained Earnings Major hydroelectric project licenses provide that after an initial 20-year period, a portion of the earnings of such project in excess of a specified rate of return is to be set aside in appropriated retained earnings in compliance with FERC Order No. 5, issued in 1978. Appropriated retained earnings included in retained earnings on the Consolidated Balance Sheets were $0.8 million at December 31, 2008 and 2007.

NOTE 18 - 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. Custom Investment Corporation and East Barnet are 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 accounting policies of operating segments are the same as those described in Part II, Item 8, Note 1 - Business Organization and Summary of Significant Accounting Policies. All segment operations are managed centrally by CV - VT. Segment profit or loss is based on profit or loss from continuing operations after income taxes and preferred stock dividends. Other Companies are below the quantitative thresholds individually and in the aggregate. Inter-segment revenues are excluded from the table below and are less than $16,000 for each period. Financial information follows (dollars in thousands):

2008	**CV - VT**	**Other Companies**	**Reclassification and Consolidating Entries**	**Consolidated**
Revenues from external customers	**$ 342,162**	**$ 1,751**	**$ (1,751)**	**$ 342,162**
Depreciation and amortizations (a)	**$ 11,862**	**$ 192**	**$ (192)**	**$ 11,862**
Operating income tax expense	**$ 4,878**	**$ 473**	**$ (473)**	**$ 4,878**
Equity in earnings of affiliates	**$ 16,264**	**$ 0**	**$ 0**	**$ 16,264**
Interest income (b)	**$ 406**	**$ 24**	**$ (24)**	**$ 406**
Interest expense	**$ 11,568**	**$ 51**	**$ (51)**	**$ 11,568**
Income from continuing operations	**$ 16,168**	**$ 217**	**$ 0**	**$ 16,385**
Investments in affiliates	**$ 102,232**	**$ 0**	**$ 0**	**$ 102,232**
Total assets	**$ 624,341**	**$ 3,184**	**$ (1,399)**	**$ 626,126**
Construction and plant expenditures (c)	**$ 36,835**	**$ 339**	**$ 0**	**$ 37,174**
2007				
Revenues from external customers	$ 329,107	$ 1,798	$ (1,798)	$ 329,107
Depreciation and amortizations (a)	$ 10,993	$ 184	$ (184)	$ 10,993
Operating income tax expense	$ 5,291	$ 329	$ (329)	$ 5,291
Equity in earnings of affiliates	$ 6,430	$ 0	$ 0	$ 6,430
Interest income (b)	$ 587	$ 58	$ 0	$ 645
Interest expense	$ 8,475	$ 47	$ 0	$ 8,522
Income from continuing operations	$ 15,317	$ 487	$ 0	$ 15,804
Investments in affiliates	$ 93,452	$ 0	$ 0	$ 93,452
Total assets	$ 538,481	$ 2,134	$ (301)	$ 540,314
Construction and plant expenditures (c)	$ 23,663	$ 250	$ 0	$ 23,913

2006								
Revenues from external customers	$	325,738	$	1,838	$	(1,838)	$	325,738
Depreciation and amortizations (a)	$	14,240	$	175	$	(175)	$	14,240
Operating income tax (benefit) expense	$	8,569	$	284	$	(284)	$	8,569
Equity in earnings of affiliates	$	3,240	$	0	$	0	$	3,240
Interest income (b)	$	1,386	$	728	$	0	$	2,114
Interest expense	$	8,231	$	0	$	0	$	8,231
Income from continuing operations	$	17,074	$	1,027	$	0	$	18,101
Investments in affiliates	$	39,339	$	0	$	0	$	39,339
Total assets	$	499,125	$	2,314	$	(501)	$	500,938
Construction and plant expenditures (d)	$	23,810	$	208	$	0	$	24,018

(a) Includes net deferral and amortization of nuclear replacement energy and maintenance costs, and amortization of regulatory assets and liabilities. These items are included in Purchased Power and Other Operation, respectively, on the Consolidated Statements of Income. Also includes capital lease amortizations.
(b) Included in Other Income on the Consolidated Statements of Income.
(c) Construction and plant expenditures for Other Companies are included in other investing activities on the Consolidated Statements of Cash Flows.
(d) Includes acquisition of utility property.

NOTE 19 - UNAUDITED QUARTERLY FINANCIAL INFORMATION

The amounts included in the table below are in thousands, except per share amounts:

				Quarter Ended						
		March		June		September		December		Total (a)
2008										
Operating revenues	**$**	**91,224**	**$**	**84,487**	**$**	**83,767**	**$**	**82,684**	**$**	**342,162**
Utility operating income	**$**	**6,432**	**$**	**4,243**	**$**	**7,315**	**$**	**440**	**$**	**18,430**
Net income	**$**	**5,908**	**$**	**4,001**	**$**	**6,481**	**$**	**(5)**	**$**	**16,385**
Basic earnings per share	**$**	**0.57**	**$**	**0.38**	**$**	**0.62**	**$**	**(0.01)**	**$**	**1.53**
Diluted earnings per share	**$**	**0.56**	**$**	**0.38**	**$**	**0.61**	**$**	**(0.01)**	**$**	**1.52**
2007										
Operating revenues	$	86,696	$	77,380	$	79,174	$	85,857	$	329,107
Utility operating income	$	6,063	$	887	$	5,147	$	5,878	$	17,975
Net income	$	5,706	$	521	$	4,321	$	5,256	$	15,804
Basic earnings per share	$	0.55	$	0.04	$	0.41	$	0.51	$	1.52
Diluted earnings per share	$	0.55	$	0.04	$	0.41	$	0.50	$	1.49

(a) The summation of quarterly earnings per share data may not equal annual data due to rounding.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure
None

Item 9A. 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 (the "Exchange Act")), as of December 31, 2008. Based on this evaluation, our Chief Executive Officer and Principal Financial and Accounting Officer concluded that, as of December 31, 2008, the company's disclosure controls and procedures are effective.

Management's Report on Internal Control Over Financial Reporting
Management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) under the Securities and Exchange Act of 1934. The company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and of the preparation and fair presentation of the Company's financial statements for external reporting purposes in accordance with generally accepted accounting principles.

Under the supervision of our Chief Executive Officer and Principal Financial and Accounting Officer, and with participation of management, we assessed the effectiveness of the company's internal control over financial reporting based on the framework established in "Internal Control - Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, we have concluded that the company's internal control over financial reporting was effective as of the end of the period covered by this report.

The effectiveness of our internal control over financial reporting has been audited by Deloitte & Touche LLP, the independent registered public accounting firm that audited our consolidated financial statements, whose report is included below.

Changes in Internal Control over Financial Reporting
There were no changes in internal control over financial reporting that occurred during the quarter ended December 31, 2008 that have materially affected, or are reasonably likely to materially affect, the company's internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Central Vermont Public Service Corporation

We have audited the internal control over financial reporting of Central Vermont Public Service Corporation and subsidiaries (the "Company") as of December 31, 2008, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and consolidated financial statement schedule as of and for the year ended December 31, 2008 of the Company and our report dated March 11, 2009 , which report also refers to the reports of other auditors, expresses an unqualified opinion on those consolidated financial statements and consolidated financial statement schedule and includes an explanatory paragraph relating to the adoption of Financial Accounting Standards Board ("FASB") Interpretation 48, *Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109*.

/s/ DELOITTE & TOUCHE LLP

Boston, Massachusetts
March 11, 2009

Item 9B. Other Information
None

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

The information required by this item is incorporated herein by reference to the section entitled "Director Elections" of the Proxy Statement of the Company for the 2009 Annual Meeting of Stockholders. The Executive Officers information is listed under Part I, Item 1. Definitive proxy materials wi be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 26, 2009.

Item 11. Executive Compensation.

The information required by this item is incorporated herein by reference to the section entitled "Summary Compensation Table" of the Proxy Stateme of the Company for the 2009 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 26, 2009.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The information required by this item related to security ownership of certain beneficial owners is incorporated herein by reference to the section entitled "Security Ownership of Certain Beneficial Owners and Management" of the Proxy Statement of the Company for the 2009 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 26 2009. The Equity Compensation Plan Information is shown in the table below.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders			
1997 Stock Option Plan for Key Employees	79,458	$15.97	-
2000 Stock Option Plan for Key Employees	182,630	$16.49	-
Omnibus Stock Plan	116,869	$20.30	154,863
Total	**378,957**	**$17.55**	**154,863**

Item 13. Certain Relationships and Related Transactions, and Director Independence.

The information required by this item is incorporated herein by reference to the sections entitled "Certain Relationships and Related Transactions" and "Board Independence" of the Proxy Statement of the Company for the 2009 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 26, 2009.

Item 14. Principal Accounting Fees and Services.

The information required by this item is incorporated herein by reference to the sections entitled "Services Performed by the Independent Registered Public Accountants" and "Independent Registered Public Accountant Fees" of the Proxy Statement of the Company for the 2009 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 26, 2009.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)1. The following financial statements are included herein under Part II, Item 8, financial Statements and Supplementary Data:

Consolidated Statements of Income for the three years ended December 31, 2008, 2007 and 2006

Consolidated Statements of Comprehensive Income for the three years ended December 31, 2008, 2007 and 2006

Consolidated Statements of Cash Flows for the three years ended December 31, 2008, 2007 and 2006

Consolidated Balance Sheets at December 31, 2008 and 2007

Consolidated Statements of Changes in Common Stock Equity at December 31, 2008, 2007 and 2006

Notes to Consolidated Financial Statements

(a)2. Schedule II - Reserves for the three years ended December 31, 2008, 2007 and 2006

(a)3. Exhibits (* denotes filed herewith)

Each document described below is incorporated by reference to the appropriate exhibit numbers and the Commission file numbers indicated in parentheses, unless the reference to the document is marked as follows:

* - Filed herewith.

Copies of any of the exhibits filed with the Securities and Exchange Commission in connection with this document may be obtained from the Company upon written request.

Exhibit 3 Articles of Incorporation and By-laws

3-1 By-laws, as amended October 8, 2005. (Exhibit 99.2, Current Report on Form 8-K Filed October 11, 2005, File No. 1-8222)

3-2 Articles of Association, as amended August 11, 1992. (Exhibit No. 3-2, 1992 10-K, File No. 1-8222)

Exhibit 4 Instruments defining the rights of security holders, including Indentures

Incorporated herein by reference:

4-1 Bond Purchase Agreement between Merrill, Lynch, Pierce, Fenner & Smith, Inc., Underwriters and The Industrial Development Authority of the State of New Hampshire, issuer and Central Vermont Public Service Corporation. (Exhibit B-46, 1984 Form 10-K, File No. 1-8222)

4-2 Bond Purchase Agreement among Connecticut Development Authority and Central Vermont Public Service Corporation with E. F. Hutton & Company Inc. dated December 11, 1985. (Exhibit B-48, 1985 Form 10-K, File No. 1-8222)

4-3 Stock-Purchase Agreement between Vermont Electric Power Company, Inc. and the Company dated August 11, 1986 relative to purchase of Class C Preferred Stock. (Exhibit B-49, 1986 Form 10-K, File No. 1-8222)

4-4 Forty-Fourth Supplemental Indenture, dated as of June 15, 2004 amending and restating the Company's Indenture of Mortgage dated as of October 1, 1929. (Exhibit 4-63, Form 10-Q, June 30, 2004, File No. 1-8222)

4-5 Forty-Fifth Supplemental Indenture, dated as of July 15, 2004 and directors' resolutions establishing the Series SS and Series TT Bonds and matter connected therewith. (Exhibit 4-64, Form 10-Q, June 30, 2004, File No. 1-8222)

4-6 Form of Bond Purchase Agreement dated as of July 15, 2004 relating to Series SS and Series TT Bonds. (Exhibit 4-65, Form 10-Q, June 30, 2004, File No. 1-8222)

4-7 Forty-Sixth Supplemental Indenture, dated as of May 1, 2008, from the Company to U.S. Bank National Association, as trustee. (Exhibit 4-7, Current Report on Form 8-K Filed May 15, 2008, File No. 1-8222)

4-8 Bond Purchase Agreement, dated as of May 15, 2008, among the Company and the purchasers listed on Schedule A thereto. (Exhibit 4-8, Current Report on Form 8-K Filed May 15, 2008, File No. 1-8222)

Exhibit 10 Material Contracts (* Denotes filed herewith)

Incorporated herein by reference:

10.1 Copy of firm power Contract dated August 29, 1958, and supplements thereto dated September 19, 1958, October 7, 1958, and October 1, 1960, between the Company and the State of Vermont (the "State"). (Exhibit C-1, File No. 2-17184)

10.1.1 Agreement setting out Supplemental NEPOOL Understandings dated as of April 2, 1973. (Exhibit C-22, File No. 5-50198)

10.2 Copy of Transmission Contract dated June 13, 1957, between Velco and the State, relating to transmission of power. (Exhibit 10.2, 1993 Form 10-K, File No. 1-8222)

10.2.1 Copy of letter agreement dated August 4, 1961, between Velco and the State. (Exhibit C-3, File No. 2-26485)

10.2.2 Amendment dated September 23, 1969. (Exhibit C-4, File No. 2-38161)

10.2.3 Amendment dated March 12, 1980. (Exhibit C-92, 1982 Form 10-K, File No. 1-8222)

10.2.4 Amendment dated September 24, 1980. (Exhibit C-93, 1982 Form 10-K, File No. 1-8222)

10.3 Copy of subtransmission contract dated August 29, 1958, between Velco and the Company (there are seven similar contracts between Velco and other utilities). (Exhibit 10.3, 1993 Form 10-K, Form No. 1-8222)

10.3.1 Copies of Amendments dated September 7, 196l, November 2, 1967, March 22, 1968, and October 29, 1968. (Exhibit C-6, File No. 2-32917)

10.3.2 Amendment dated December 1, 1972. (Exhibit 10.3.2, 1993 Form 10-K, File No. 1-8222)

10.4 Copy of Three-Party Agreement dated September 25, 1957, between the Company, Green Mountain and Velco. (Exhibit C-7, File No. 2-17184)

10.4.1 Amended and Restated Three-Party Agreement between the Company, Green Mountain Power Corporation, Vermont Electric Power Company, Inc., and Vermont Transco, LLC effective June 30, 2006. (Exhibit 10.4.3, 2006 Form 10-K, File No. 1-8222)

10.5 Copy of firm power Contract dated December 29, 1961, between the Company and the State, relating to purchase of Niagara Project power. (Exhibit C-8, File No. 2-26485)

10.5.1 Amendment effective as of January 1, 1980. (Exhibit 10.5.1, 1993 Form 10-K, File No. 1-8222)

10.7 Copy of Capital Funds Agreement between the Company and Vermont Yankee dated as of February 1, 1968. (Exhibit C-11, File No. 70-4611)

10.7.1 Copy of Amendment dated March 12, 1968. (Exhibit C-12, File No. 70-4611)

10.7.2 Copy of Amendment dated September 1, 1993. (Exhibit 10.7.2, 1994 Form 10-K, File No. 1-8222)

10.8 Copy of Power Contract between the Company and Vermont Yankee dated as of February 1, 1968. (Exhibit C-13, File No. 70-4591)

10.8.1 Amendment dated April 15, 1983. (10.8.1, 1993 Form 10-K, File No. 1-8222)

10.8.2 Copy of Additional Power Contract dated February 1, 1984. (Exhibit C-123, 1984 Form 10-K, File No. 1-8222)

10.8.3 Amendment No. 3 to Vermont Yankee Power Contract, dated April 24, 1985. (Exhibit 10-144, 1986 Form 10-K, File No. 1-8222)

10.8.4 Amendment No. 4 to Vermont Yankee Power Contract, dated June 1, 1985. (Exhibit 10-145, 1986 Form 10-K, File No. 1-8222)

10.8.5 Amendment No. 5 dated May 6, 1988. (Exhibit 10-179, 1988 Form 10-K, File No. 1-8222)

10.8.6 Amendment No. 6 dated May 6, 1988. (Exhibit 10-180, 1988 Form 10-K, File No. 1-8222)

10.8.7 Amendment No. 7 dated June 15, 1989. (Exhibit 10-195, 1989 Form 10-K, File No. 1-8222)

10.8.8 Amendment No. 8 dated November 17, 1999. (Exhibit 10.8.8, Form 10-Q, June 30, 2000, File No. 1-8222)

10.8.9 Amendment No. 9 dated November 17, 1999. (Exhibit 10.8.9, Form 10-Q, June 30, 2000, File No. 1-8222)

10.8.10 2001 Amendatory Agreement dated as of September 21, 2001 to which the Company is a party re: Vermont Yankee Nuclear Power Corporation Power Contract. (Exhibit 10.8.10, Form 10-Q, September 30, 2001, File No. 1-8222)

10.9 Copy of Capital Funds Agreement between the Company and Maine Yankee dated as of May 20, 1968. (Exhibit C-14, File No. 70-4658)

10.9.1 Amendment No. 1 dated August 1, 1985. (Exhibit C-125, 1984 Form 10-K, File No. 1-8222)

10.10 Copy of Power Contract between the Company and Maine Yankee dated as of May 20, 1968. (Exhibit C-15, File No. 70-4658)

10.10.1 Amendment No. 1 dated March 1, 1984. (Exhibit C-112, 1984 Form 10-K, File No. 1-8222)

10.10.2 Amendment No. 2 effective January 1, 1984. (Exhibit C-113, 1984 Form 10-K, File No. 1-8222)

10.10.3 Amendment No. 3 dated October 1, 1984. (Exhibit C-114, 1984 Form 10-K, File No. 1-8222)

10.10.4 Additional Power Contract dated February 1, 1984. (Exhibit C-126, 1985 Form 10-K, File No. 1-8222)

10.11 Copy of Three-Party Power Agreement dated as of November 21, 1969, among the Company, Velco, and Green Mountain relating to purchase and sale of power from Vermont Yankee Nuclear Power Corporation. (Exhibit C-18, File No. 2-38161)

10.11.1 Amendment dated June 1, 1981. (Exhibit 10.13.1, 1993 Form 10-K, File No. 1-8222)

10.11.2 Superseding Three Party Power Agreement dated January 1, 1990. (Exhibit 10-201, 1990 Form 10-K, File No. 1-8222)

10.11.3 Agreement Amending Superseding Three Party Power Agreement dated May 1, 1991. (Exhibit 10.4.2, 1991 Form 10-K, File No. 1-8222)

10.12 Copy of Three-Party Transmission Agreement dated as of November 21, 1969, among the Company, Velco, and Green Mountain providing for transmission of power from Vermont Yankee Nuclear Power Corporation. (Exhibit C-19, File No. 2-38161)

10.12.1 Amendment dated June 1, 1981. (Exhibit 10.14.1, 1993 Form 10-K, File No. 1-8222)

10.12.2 Amended and Restated Three-Party Transmission Agreement between the Company, Green Mountain Power Corporation, Vermont Electric Power Company, Inc., and Vermont Transco, LLC effective November 30, 2006. (Exhibit 10.14.2, 2006 Form 10-K, File No. 1-8222)

10.13 Copy of Stockholders Agreement dated September 25, 1957, between the Company, Velco, Green Mountain and Citizens Utilities Company. (Exhibit No. C-20, File No. 70-3558)

10.14 New England Power Pool Agreement dated as of September 1, 1971, as amended to November 1, 1975. (Exhibit C-21, File No. 2-55385)

10.14.1 Amendment dated December 31, 1976. (Exhibit 10.16.1, 1993 Form 10-K, File No. 1-8222)

10.14.2 Amendment dated January 23, 1977. (Exhibit 10.16.2, 1993 Form 10-K, File No. 1-8222)

10.14.3 Amendment dated July 1, 1977. (Exhibit 10.16.3, 1993 Form 10-K, File No. 1-8222)

10.14.4 Amendment dated August 1, 1977. (Exhibit 10.16.4, 1993 Form 10-K, File No. 1-8222)

10.14.5 Amendment dated August 15, 1978. (Exhibit 10.16.5, 1993 Form 10-K, File No. 1-8222)

10.14.6 Amendment dated January 31, 1979. (Exhibit 10.16.6, 1993 Form 10-K, File No. 1-8222)

10.14.7 Amendment dated February 1, 1980. (Exhibit 10.16.7, 1993 Form 10-K, File No. 1-8222)

10.14.8 Amendment dated December 31, 1976. (Exhibit 10.16.8, 1993 Form 10-K, File No. 1-8222)

10.14.9 Amendment dated January 31, 1977. (Exhibit 10.16.9, 1993 Form 10-K, File No. 1-8222)

10.14.10 Amendment dated July 1, 1977. (Exhibit 10.16.10, 1993 Form 10-K, File No. 1-8222)

10.14.11 Amendment dated August 1, 1977. (Exhibit 10.16.11, 1993 Form 10-K, File No. 1-8222)

10.14.12 Amendment dated August 15, 1978. (Exhibit 10.16.12, 1993 Form 10-K, File No. 1-8222)

10.14.13 Amendment dated January 31, 1980. (Exhibit 10.16.13, 1993 Form 10-K, File No. 1-8222)

10.14.14 Amendment dated February 1, 1980. (Exhibit 10.16.14, 1993 Form 10-K, File No. 1-8222)

10.14.15 Amendment dated September 1, 1981. (Exhibit 10.16.15, 1993 Form 10-K, File No. 1-8222)

10.14.16 Amendment dated December 1, 1981. (Exhibit 10.16.16, 1993 Form 10-K, File No. 1-8222)

10.14.17 Amendment dated June 15, 1983. (Exhibit 10.16.17, 1993 Form 10-K, File No. 1-8222)

10.14.18 Amendment dated September 1, 1985. (Exhibit 10-160, 1986 Form 10-K, File No. 1-8222)

10.14.19 Amendment dated April 30, 1987. (Exhibit 10-172, 1987 Form 10-K, File No. 1-8222)

10.14.20 Amendment dated March 1, 1988. (Exhibit 10-178, 1988 Form 10-K, File No. 1-8222)

10.14.21 Amendment dated March 15, 1989. (Exhibit 10-194, 1989 Form 10-K, File No. 1-8222)

10.14.22 Amendment dated October 1, 1990. (Exhibit 10-203, 1990 Form 10-K, File No. 1-8222)

10.14.23 Amendment dated September 15, 1992. (Exhibit 10.16.23, 1992 Form 10-K, File No. 1-8222)

10.14.24 Amendment dated May 1, 1993. (Exhibit 10.16.24, 1993 Form 10-K, File No. 1-8222)

10.14.25 Amendment dated June 1, 1993. (Exhibit 10.16.25, 1993 Form 10-K, File No. 1-8222)

10.14.26 Amendment dated June 1, 1994. (Exhibit 10.16.26, 1994 Form 10-K, File No. 1-8222)

10.14.27 Thirty-Second Amendment dated September 1, 1995. (Exhibit 10.16.27, Form 10-Q dated September 30, 1995, File No. 1-8222 and Exhibit 10.16.27, 1995 Form 10-K, File No. 1-8222)

10.14.28 Security Agreement dated October 7, 2003 between Central Vermont Public Service Corporation and ISO New England Inc. (Exhibit 10.16.28, Form 10-Q, September 30, 2003, File No. 1-8222)

10.15 Sharing Agreement - 1979 Connecticut Nuclear Unit dated September 1, 1973, to which the Company is a party. (Exhibit C-40, File No. 2-50142)

10.15.1 Amendment dated as of August 1, 1974. (Exhibit C-41, File No. 2-51999)

10.15.2 Instrument of Transfer dated as of February 28, 1974, transferring partial interest from the Company to Green Mountain. (Exhibit C-42, File No. 2-52177)

10.15.3 Instrument of Transfer dated January 17, 1975, transferring a partial interest from the Company to Burlington Electric Department. (Exhibit C-43, File No. 2-55458)

10.15.4 Amendment dated May 11, 1984. (Exhibit C-110, 1984 Form 10-K, File No. 1-8222)

10.16 Agreement for Joint Ownership, Construction and Operation of William F. Wyman Unit No. 4 dated November 1, 1974, among Central Maine Power Company and other utilities including the Company. (Exhibit C-46, File No. 2-52900)

10.16.1 Amendment dated as of June 30, 1975. (Exhibit C-47, File No. 2-55458)

10.16.2 Instrument of Transfer dated July 30, 1975, assigning a partial interest from Velco to the Company. (Exhibit C-48, File No. 2-55458)

10.17 Transmission Agreement dated November 1, 1974, among Central Maine Power Company and other utilities including the Company with respect to William F. Wyman Unit No. 4. (Exhibit C-49, File No. 2-54449)

10.18 Copy of Power Contract between the Company and Yankee Atomic dated as of June 30, 1959. (Exhibit C-61, 1981 Form 10-K, File No. 1-8222)

10.18.1 Revision dated April 1, 1975. (Exhibit C-61, 1981 Form 10-K, File No. 1-8222)

10.18.2 Amendment dated May 6, 1988. (Exhibit 10-181, 1988 Form 10-K, File No. 1-8222)

10.18.3 Amendment dated June 26, 1989. (Exhibit 10-196, 1989 Form 10-K, File No. 1-8222)

10.18.4 Amendment dated July 1, 1989. (Exhibit 10-197, 1989 Form 10-K, File No. 1-8222)

10.18.5 Amendment dated February 1, 1992 (Exhibit 10.25.5, 1992 Form 10-K, File No. 1-8222)

10.18.6 Amendment to the Power Contract between the Company and Yankee Atomic Electric Company dated October 1, 1980. (Exhibit 10.25.6, Form 10-Q, September 30, 2006, File No. 1-8222)

10.18.7 Amendment No. 3 to the Power Contract between the Company and Yankee Atomic Electric Company dated April 1, 1985. (Exhibit 10.25.7, Form 10-Q, September 30, 2006, File No. 1-8222)

10.18.8 Amendment No. 8 to the Power Contract between the Company and Yankee Atomic Electric Company dated June 1, 2003. (Exhibit 10.25.8, Form 10-Q, September 30, 2006, File No. 1-8222)

10.18.9 Amendment No. 9 to the Power Contract between the Company and Yankee Atomic Electric Company dated November 17, 2005. (Exhibit 10.25.9, Form 10-Q, September 30, 2006, File No. 1-8222)

10.18.10 Amendment No. 10 to the Power Contract between the Company and Yankee Atomic Electric Company dated April 14, 2006. (Exhibit 10.25.10, Form 10-Q, September 30, 2006, File No. 1-8222)

10.19 Copy of Transmission Contract between the Company and Yankee Atomic dated as of June 30, 1959. (Exhibit C-63, 1981 Form 10-K, File No. 1-8222)

10.20 Copy of Power Contract between the Company and Connecticut Yankee dated as of June 1, 1964. (Exhibit C-64, 1981 Form 10-K, File No. 1-8222)

10.20.1 Supplementary Power Contract dated March 1, 1978. (Exhibit C-94, 1982 Form 10-K, File No. 1-8222)

10.20.2 Amendment dated August 22, 1980. (Exhibit C-95, 1982 Form 10-K, File No. 1-8222)

10.20.3 Amendment dated October 15, 1982. (Exhibit C-96, 1982 Form 10-K, File No. 1-8222)

10.20.4 Second Supplementary Power Contract dated April 30, 1984. (Exhibit C-115, 1984 Form 10-K, File No. 1-8222)

10.20.5 Additional Power Contract dated April 30, 1984. (Exhibit C-116, 1984 Form 10-K, File No. 1-8222)

10.20.6 1987 Supplementary Power Contract, dated as of April 1, 1987. (Exhibit 10.27.6, Form 10-Q, June 30, 2000, File No. 1-8222)

10.20.7 1996 Amendatory Agreement, dated December 1, 1996. (Exhibit 10.27.7, Form 10-Q, June 30, 2000, File No. 1-8222)

10.20.8 2000 Amendatory Agreement, dated May, 2000. (Exhibit 10.27.8, Form 10-Q, June 30, 2000, File No. 1-8222)

10.21 Copy of Transmission Contract between the Company and Connecticut Yankee dated as of July 1, 1964. (Exhibit C-65, 1981 Form 10-K, File No. 1-8222)

10.22 Copy of Capital Funds Agreement between the Company and Connecticut Yankee dated as of July 1, 1964. (Exhibit C-66, 1981 Form 10-K, File No. 1-8222)

10.22.1 Copy of Capital Funds Agreement between the Company and Connecticut Yankee dated as of September 1, 1964. (Exhibit C-67, 1981 Form 10-K, File No. 1-8222)

10.23 Copy of Five-Year Capital Contribution Agreement between the Company and Connecticut Yankee dated as of November 1, 1980. (Exhibit C-68, 1981 Form 10-K, File No. 1-8222)

10.24 Form of Guarantee Agreement dated as of November 7, 1981, among certain banks, Connecticut Yankee and the Company, relating to revolving credit notes of Connecticut Yankee. (Exhibit C-69, 1981 Form 10-K, File No. 1-8222)

10.25 Form of Guarantee Agreement dated as of November 13, 1981, between The Connecticut Bank and Trust Company, as Trustee, and the Company, relating to debentures of Connecticut Yankee. (Exhibit C-70, 1981 Form 10-K, File No. 1-8222)

10.26 Preliminary Vermont Support Agreement re Quebec interconnection between Velco and among seventeen Vermont Utilities dated May 1, 1981. (Exhibit C-97, 1982 Form 10-K, File No. 1-8222)

10.26.1 Amendment dated June 1, 1982. (Exhibit C-98, 1982 Form 10-K, File No. 1-8222)

10.27 Vermont Participation Agreement for Quebec Interconnection between Velco and among seventeen Vermont Utilities dated July 15, 1982. (Exhibit C-99, 1982 Form 10-K, File No. 1-8222)

10.27.1 Amendment No. 1 dated January 1, 1986. (Exhibit C-132, 1986 Form 10-K, File No. 1-8222)

10.28 Vermont Electric Transmission Company Capital Funds Support Agreement between Velco and among sixteen Vermont Utilities dated July 15, 1982. (Exhibit C-100, 1982 Form 10-K, File No. 1-8222)

10.29 Vermont Transmission Line Support Agreement, Vermont Electric Transmission Company and twenty New England Utilities dated December 1, 1981, as amended by Amendment No. 1 dated June 1, 1982, and by Amendment No. 2 dated November 1, 1982. (Exhibit C-101, 1982 Form 10-K, File No. 1-8222)

10.29.1 Amendment No. 3 dated January 1, 1986. (Exhibit 10-149, 1986 Form 10-K, File No. 1-8222)

10.30 Phase 1 Terminal Facility Support Agreement between New England Electric Transmission Corporation and twenty New England Utilities dated December 1, 1981, as amended by Amendment No. 1 dated as of June 1, 1982 and by Amendment No. 2 dated as of November 1, 1982. (Exhibit C-102, 1982 Form 10-K, File No. 1-8222)

10.31 Power Purchase Agreement between Velco and CVPS dated June 1, 1981. (Exhibit C-103, 1982 Form 10-K, File No. 1-8222)

10.32 Agreement for Joint Ownership, Construction and Operation of the Joseph C. McNeil Generating Station by and between City of Burlington Electric Department, Central Vermont Realty, Inc. and Vermont Public Power Supply Authority dated May 14, 1982. (Exhibit C-107, 1983 Form 10-K, File No. 1-8222)

10.32.1 Amendment No. 1 dated October 5, 1982. (Exhibit C-108, 1983 Form 10-K, File No. 1-8222)

10.32.2 Amendment No. 2 dated December 30, 1983. (Exhibit C-109, 1983 Form 10-K, File No. 1-8222)

10.32.3 Amendment No. 3 dated January 10, 1984. (Exhibit 10-143, 1986 Form 10-K, File No. 1-8222)

10.33 Transmission Service Contract between Central Vermont Public Service Corporation and The Vermont Electric Generation & Transmission Cooperative, Inc. dated May 14, 1984. (Exhibit C-111, 1984 Form 10-K, File No. 1-8222)

10.34 Copy of Highgate Transmission Interconnection Preliminary Support Agreement dated April 9, 1984. (Exhibit C-117, 1984 Form 10-K, File No. 1-8222)

10.35 Copy of Allocation Contract for Hydro-Quebec Firm Power dated July 25, 1984. (Exhibit C-118, 1984 Form 10-K, File No. 1-8222)

10.35.1 Tertiary Energy for Testing of the Highgate HVDC Station Agreement, dated September 20, 1985. (Exhibit C-129, 1985 Form 10-K, File No. 1-8222)

10.36 Copy of Highgate Operating and Management Agreement dated August 1, 1984. (Exhibit C-119, 1986 Form 10-K, File No. 1-8222)

10.36.1 Amendment No. 1 dated April 1, 1985. (Exhibit 10-152, 1986 Form 10-K, File No. 1-8222)

10.36.2 Amendment No. 2 dated November 13, 1986. (Exhibit 10-167, 1987 Form 10-K, File No. 1-8222)

10.36.3 Amendment No. 3 dated January 1, 1987. (Exhibit 10-168, 1987 Form 10-K, File No. 1-8222)

*10.36.4 Amendment No. 4 dated December 1, 2008.

10.37 Copy of Highgate Construction Agreement dated August 1, 1984. (Exhibit C-120, 1984 Form 10-K, File No. 1-8222)

10.37.1 Amendment No. 1 dated April 1, 1985. (Exhibit 10-151, 1986 Form 10-K, File No. 1-8222)

10.38 Copy of Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection. (Exhibit C-121, 1984 Form 10-K, File No. 1-8222)

10.38.1 Amendment No. 1 dated April 1, 1985. (Exhibit 10-153, 1986 Form 10-K, File No. 1-8222)

10.38.2 Amendment No. 2 dated April 18, 1985. (Exhibit 10-154, 1986 Form 10-K, File No. 1-8222)

10.38.3 Amendment No. 3 dated February 12, 1986. (Exhibit 10-155, 1986 Form 10-K, File No. 1-8222)

10.38.4 Amendment No. 4 dated November 13, 1986. (Exhibit 10-169, 1987 Form 10-K, File No. 1-8222)

10.38.5 Amendment No. 5 and Restatement of Agreement dated January 1, 1987. (Exhibit 10-170, 1987 Form 10-K, File No. 1-8222)

10.39 Copy of the Highgate Transmission Agreement dated August 1, 1984. (Exhibit C-122, 1984 Form 10-K, File No. 1-8222)

10.40 Copy of Preliminary Vermont Support Agreement Re: Quebec Interconnection - Phase II dated September 1, 1984. (Exhibit C-124, 1984 Form 10-K, File No. 1-8222)

10.40.1 First Amendment dated March 1, 1985. (Exhibit C-127, 1985 Form 10-K, File No. 1-8222)

10.41 Vermont Transmission and Interconnection Agreement between New England Power Company and Central Vermont Public Service Corporation and Green Mountain Power Corporation with the consent of Vermont Electric Power Company, Inc., dated May 1, 1985. (Exhibit C-128, 1985 Form 10-K, File No. 1-8222)

10.42 System Sales & Exchange Agreement Between Niagara Mohawk Power Corporation and Central Vermont Public Service Corporation dated October 1, 1986. (Exhibit C-133, 1986 Form 10-K, File No. 1-8222)

10.43 Transmission Agreement between Vermont Electric Power Company, Inc. and Central Vermont Public Service Corporation dated January 1, 1986. (Exhibit 10-146, 1986 Form 10-K, File No. 1-8222)

10.44 1985 Four-Party Agreement between Vermont Electric Power Company, Central Vermont Public Service Corporation, Green Mountain Power Corporation and Citizens Utilities dated July 1, 1985. (Exhibit 10-147, 1986 Form 10-K, File No. 1-8222)

10.44.1 Amendment dated February 1, 1987. (Exhibit 10-171, 1987 Form 10-K, File No. 1-8222)

10.45 1985 Option Agreement between Vermont Electric Power Company, Central Vermont Public Service Corporation, Green Mountain Power Corporation and Citizens Utilities dated December 27, 1985. (Exhibit 10-148, 1986 Form 10-K, File No. 1-8222)

10.45.1 Amendment No. 1 dated September 28, 1988. (Exhibit 10-182, 1988 Form 10-K, File No. 1-8222)

10.45.2 Amendment No. 2 dated October 1, 1991. (Exhibit 10.56.2, 1991 Form 10-K, File No. 1-8222)

10.45.3 Amendment No. 3 dated December 31, 1994. (Exhibit 10.56.3, 1994 Form 10-K, File No. 1-8222)

10.45.4 Amendment No. 4 dated December 31, 1996. (Exhibit 10.56.4, 1996 Form 10-K, file No. 1-8222)

10.46 Highgate Transmission Agreement dated August 1, 1984 by and between the owners of the project and the Vermont electric distribution companies. (Exhibit 10-156, 1986 Form 10-K, File No. 1-8222)

10.46.1 Amendment No. 1 dated September 22, 1985. (Exhibit 10-157, 1986 Form 10-K, File No. 1-8222)

10.47 Vermont Support Agency Agreement re: Quebec Interconnection - Phase II between Vermont Electric Power Company, Inc. and participating Vermont electric utilities dated June 1, 1985. (Exhibit 10-158, 1986 Form 10K, File No. 1-8222)

10.47.1 Amendment No. 1 dated June 20, 1986. (Exhibit 10-159, 1986 Form 10-K, File No. 1-8222)

10.48 Indemnity Agreement B-39 dated May 9, 1969 with amendments 1-16 dated April 17, 1970 thru April 16, 1985 between licensees of Millstone Unit No. 3 and the Nuclear Regulatory Commission. (Exhibit 10-161, 1986 Form 10-K, File No. 1-8222)

10.48.1 Amendment No. 17 dated November 25, 1985. (Exhibit 10-162, 1986 Form 10-K, File No. 1-8222)

10.49 Contract for the Sale of 50MW of firm power between Hydro-Quebec and Vermont Joint Owners of Highgate Facilities dated February 23, 1987. (Exhibit 10-173, 1987 Form 10-K, File No. 1-8222)

10.50 Interconnection Agreement between Hydro-Quebec and Vermont Joint Owners of Highgate facilities dated February 23, 1987. (Exhibit 10-174, 1987 Form 10-K, File No. 1-8222)

10.50.1 Amendment dated September 1, 1993 (Exhibit 10.63.1, 1993 Form 10-K, File No. 1-8222)

10.51 Firm Power and Energy Contract by and between Hydro-Quebec and Vermont Joint Owners of Highgate for 500MW dated December 4, 1987. (Exhibit 10-175, 1987 Form 10-K, File No. 1-8222)

10.51.1 Amendment No. 1 dated August 31, 1988. (Exhibit 10-191, 1988 Form 10-K, File No. 1-8222)

10.51.2 Amendment No. 2 dated September 19, 1990. (Exhibit 10-202, 1990 Form 10-K, File No. 1-8222)

10.51.3 Firm Power & Energy Contract dated January 21, 1993 by and between Hydro-Quebec and Central Vermont Public Service Corporation for the sale back of 25 MW of power. (Exhibit 10.64.3, 1992 Form 10-K, File No. 1-8222)

10.51.4 Firm Power & Energy Contract dated January 21, 1993 by and between Hydro-Quebec and Central Vermont Public Service Corporation for the sale back of 50 MW of power. (Exhibit 10.64.4, 1992 Form 10-K, File No. 1-8222)

10.52 Hydro-Quebec Participation Agreement dated April 1, 1988 for 600 MW between Hydro-Quebec and Vermont Joint Owners of Highgate. (Exhibit 10-177, 1988 Form 10-K, File No. 1-8222)

10.52.1 Hydro-Quebec Participation Agreement dated April 1, 1988 as amended and restated by Amendment No. 5 thereto dated October 21, 1993, among Vermont utilities participating in the purchase of electricity under the Firm Power and Energy Contract by and between Hydro-Quebec and Vermont Joint Owners of Highgate. (Exhibit 10.66.1, 1997 Form 10-Q, March 31, 1997, File. No. 1-8222)

10.53 Sale of firm power and energy (54MW) between Hydro-Quebec and Vermont Utilities dated December 29, 1988. (Exhibit 10-183, 1988 Form 10-K, File No. 1-8222)

10.54 Settlement Agreement effective dated June 1, 2001 to which the Company is a party re: Vermont Yankee Nuclear Power Corporation. (Exhibit 10-84, Form 10-Q, June 30, 2001, File No. 1-8222)

10.55 Form of Secondary Purchaser Settlement Agreement dated December 6, 2001, with Acknowledgement and Consent of VELCO, among the Company, Green Mountain Power Corporation and each of: City of Burlington Electric Department; Village of Lyndonville Electric Department; Village of Northfield Electric Department; Village of Orleans Electric Department; Town of Hardwick Electric Department; Town of Stowe Electric Department; and, Washington Electric Cooperative. (Exhibit 10-85, 2001 Form 10-K, File No. 1-8222)

10.56 Memorandum of Understanding, dated September 11, 2006, between the Vermont Department of Public Service and Central Vermont Public Service Corporation. (Exhibit 10.93, Current Report on Form 8-K Filed September 11, 2006, File No. 1-8222)

10.56.1 First Amendment to Memorandum of Understanding, dated November 3, 2006, between the Vermont Department of Public Service and Central Vermont Public Service Corporation. (Exhibit 10.93, Current Report on Form 8-K Filed November 6, 2006, File No. 1-8222)

10.57 Operating Agreement of Vermont Transco, LLC effective July 1, 2006. (Exhibit 10.94, 2006 Form 10-K, File No. 1-8222)

10.58 Amended and Restated 1991 Transmission Agreement between Vermont Transco, LLC and (to electric utilities furnishing service within the State of Vermont) effective June 20, 2006. (Exhibit 10.95, 2006 Form 10-K, File No. 1-8222)

10.59 Memorandum of Understanding, dated November 29, 2007, between the Vermont Department of Public Service and Central Vermont Public Service Corporation. (Exhibit 10.96, Current Report on Form 8-K Filed November 30, 2007, File No. 1-8222)

10.60 Credit Agreement dated as of December 28, 2007 between Central Vermont Public Service Corporation, as Borrower and KeyBank National Association, as Lender. (Exhibit 10.97, Current Report of Form 8-K Filed January 4, 2008, File No. 1-8222)

10.61 Credit Agreement dated as of November 3, 2008 between Central Vermont Public Service Corporation, as Borrower and KeyBank National Association, as Lender. (Exhibit 10.98, Current Report on Form 8-K Filed November 7, 2008, File No. 1-8222)

10.62 Memorandum of Understanding, dated December 17, 2008, between the Vermont Department of Public Service and Central Vermont Public Service Corporation. (Exhibit 10.99, Current Report on Form 8-K Filed December 18, 2008, File No. 1-8222)

10.63 Agreement between Central Vermont Public Service Corporation and Local Union No. 300 International Brotherhood of Electrical Workers Effective as of January 1, 2009. (Exhibit 10.100, Current Report on Form 8-K Filed January 7, 2009, File No. 1-8222)

EXECUTIVE COMPENSATION PLANS AND ARRANGEMENTS

A 10.1 Directors' Supplemental Deferred Compensation Plan dated November 4, 1985. (Exhibit 10-188, 1988 Form 10-K, File No. 1-8222)

A 10.1.1 Amendment dated October 2, 1995. (Exhibit 10.72.1, 1995 Form 10-K, File No. 1-8222)

A 10.2 Directors' Supplemental Deferred Compensation Plan dated January 1, 1990 (Exhibit 10.80, 1993 Form 10-K, File No. 1-8222)

A 10.2.1 Amendment dated October 2, 1995. (Exhibit No. 10.80.1, 1995 Form 10-K, File No. 1-8222)

A 10.3 Officers' Supplemental Retirement and Deferred Compensation Plan, Amended and Restated August 4, 2008, With an Effective Dated of January 1, 2008. (Exhibit A 10.3.1, Form 10-Q, June 30, 2008, File No. 1-8222)

A 10.4 1997 Stock Option Plan for Key Employees (Exhibit 4.3 to Registration Statement, Registration 333-57001)

A 10.5 Officers' Change of Control Agreements as approved April 3, 2000. (Exhibit A 10.92, Form 10-Q, March 31, 2000, File No. 1-8222)

A 10.5.1 Form of Change In Control Agreement as Amended May 6, 2008. (Exhibit A 10.5.1, Form 10-Q, March 31, 2008, File No. 1-8222)

A 10.6 Form of Change In Control Agreement to Become Effective April 2009. (Exhibit A 10.5.2, Form 10-Q, March 31, 2008, File No. 1-8222)

A 10.7 2000 Stock Option Plan for Key Employees. (Previously filed as Schedule A, Form DEF 14A - Proxy Statement, March 28, 2000, File No. 1-8222) - (Exhibit A 10.95, September 30, 2006 Form 10-Q, File No. 1-8222)

A 10.8 Deferred Compensation Plan for Officers and Directors of Central Vermont Public Service Corporation, Amended and Restated Effective August 4, 2008, With An Effective Date of January 1, 2005. (Exhibit A 10.7.1, Form 10-Q, June 30, 2008, File No. 1-8222)

* A 10.9 Omnibus Stock Plan (Amended and Restated 2002 Long-Term Incentive Plan). (Previously filed as Schedule A, Form DEF 14A - Proxy Statement, March 28, 2008, File No. 1-8222)

A 10.10 Performance Share Incentive Plan, Effective January 1, 2007. (Exhibit A 10.100.3, 2006 Form 10-K, File No. 1-8222)

A 10.10.1 Performance Share Incentive Plan, Effective January 1, 2007 and Amended January 1, 2008. (Exhibit A 10.10.1, 2007 Form 10-K, File No. 1-8222)

A 10.11 Performance Share Incentive Plan, Effective January 1, 2008. (Exhibit A 10.11, 2007 Form 10-K, File No. 1-8222)

A 10.12 Form of Central Vermont Public Service Performance Share Agreement Pursuant to the Performance Share Incentive Plan. (Exhibit A 10.101, Form 10-Q, September 30, 2004, File No. 1-8222)

A 10.13 Form of Central Vermont Public Service Corporation Stock Option Agreement Pursuant to the 2002 Long-Term Incentive Plan. (Exhibit A 10.102, Form 10-Q, September 30, 2004, File No. 1-8222)

A 10.14 Form of Central Vermont Public Service Corporation Stock Option Agreement Pursuant to the 2000 Stock Option Plan for Key Employees of Central Vermont Public Service Corporation. (Exhibit A 10.103, Form 10-Q, September 30, 2004, File No. 1-8222)

A 10.15 Form of Central Vermont Public Service Corporation Stock Option Agreement Pursuant to the 1997 Stock Option Plan for Key Employees of Central Vermont Public Service Corporation. (Exhibit A 10.104, Form 10-Q, September 30, 2004, File No. 1-8222)

A 10.16 Form of Indemnity Agreement between Directors and Executive Officers and Central Vermont Public Service Corporation. (Exhibit A 10.105, 2004 Form 10-K, File No. 1-8222)

A - Compensation related plan, contract, or arrangement.

12 Statements Regarding Computation of Ratios

* 12.1 Statements Regarding Computation of Ratios

21 Subsidiaries of the Registrant

* 21.1 List of Subsidiaries of Registrant

23 Consent of Independent Registered Public Accounting Firm

* 23.1 Consent of Independent Registered Public Accounting Firm (D&T)

* 23.2 Consent of Independent Registered Public Accounting Firm (KPMG - VELCO)

* 23.3 Consent of Independent Registered Public Accounting Firm (KPMG - VT Transco)

24 Power of Attorney

* 24.1 Power of Attorney executed by Directors and Officers of Company

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

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

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

* 99.1 Financial Statements of Vermont Electric Power Company, Inc. and Subsidiary

* 99.2 Financial Statements of Vermont Transco LLC.

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
Schedule II - Valuation and Qualifying Accounts

For the Years Ended December 31	Balance at beginning of year	Additions: Charged to cost and expenses	Additions: Charged to other accounts	Deductions	Balance at end of year
2008					
Reserves deducted from assets to which they apply:					
			$112,413(1)		
			$474,398(2)		
Reserve for uncollectible accounts receivable	$1,751,069	$2,472,997	$586,811	$2,627,277(3)	$2,183,600
Reserve for uncollectible accounts receivable - affiliates	$47,848			$47,848	$0
Accumulated depreciation of non-utility property	$3,681,992	$202,767		$227,349	$3,657,410
Reserves shown separately:					
Environmental Reserve	$1,917,674			$186,123	$1,731,551
2007					
Reserves deducted from assets to which they apply:					
			$127,125(1)		
			$405,882(2)		
Reserve for uncollectible accounts receivable	$1,706,747	$2,412,498	$533,007	$2,901,183(3)	$1,751,069
Reserve for uncollectible accounts receivable - affiliates	$47,848				$47,848
				$234,401	
				$330,899(7)	
Accumulated depreciation of non-utility property	$4,047,663	$199,629		$565,300	$3,681,992
Reserves shown separately:					
Environmental Reserve	$2,076,282			$158,608	$1,917,674
2006					
Reserves deducted from assets to which they apply:					
			$106,373(1)	$1,757,826(3)	
			$762,154(2)	$1,390,104(5)	
Reserve for uncollectible accounts receivable	$2,614,137	$1,372,013	$868,527	$3,147,930	$1,706,747
Reserve for uncollectible accounts receivable - affiliates	$47,913			$65	$47,848
Accumulated depreciation of non-utility property	$4,063,491	$201,469		$217,297	$4,047,663
Reserves shown separately:					
Injuries and damages reserve (4)	$200,000			$200,000	$0
Environmental Reserve	$5,426,110			$3,349,828(6)	$2,076,282

Notes:

(1) Amount collected from collection agencies
(2) Collections of accounts previously written off
(3) Uncollectible accounts written off
(4) This represents our long-term reserve for injuries & damages needed to meet our liability not covered by insurance. We are self-insured $200,000; therefore, any activity for the year is charged to expense and recorded to the current liability
(5) Settlement of accounts related to pole attachment tariff resolution
(6) Reduction of reserve based on updated cost estimates for remediation
(7) Reclassified to utility property

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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
Vice President, Chief Financial Officer, and Treasurer

March 12, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 12, 2009.

Signature	Title
Robert H. Young*	President and Chief Executive Officer, and Director (Principal Executive Officer)
/s/ Pamela J. Keefe (Pamela J. Keefe)	Vice President, Chief Financial Officer, and Treasurer (Principal Financial and Accounting Officer)
Mary Alice McKenzie*	Chair of the Board of Directors
Robert L. Barnett*	Director
Robert G. Clarke*	Director
Bruce M. Lisman*	Director
William R. Sayre*	Director
Janice L. Scites*	Director
William J. Stenger*	Director
Douglas J. Wacek*	Director

By: /s/ Pamela J. Keefe
(Pamela J. Keefe)
Attorney-in-Fact for each of the persons indicated.

* Such signature has been affixed pursuant to a Power of Attorney filed as an exhibit hereto and incorporated herein by reference thereto.