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

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2006

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission file number 1-8222

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

Vermont **(State or other jurisdiction of incorporation or organization)**	03-0111290 **(IRS Employer Identification No.)**
77 Grove Street, Rutland, Vermont **(Address of principal executive offices)**	05701 **(Zip Code)**
Registrant's telephone number, including area code	(800) 649-2877

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_X_

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_X_

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes_X_ No___

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. **[X]**

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

Large accelerated filer [ ]   Accelerated filer **[X]**   Non-accelerated filer [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes___ No__X__

The aggregate market value of voting and non-voting common equity held by non affiliates of the registrant as of June 30, 2006 (2^{nd} quarter) was approximately $151,691,120 (based on the $18.48 per share closing price of the Company's Common Stock, $6 Par Value, as reported on the New York Stock Exchange Market on June 30, 2006). 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, 2006, 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 28, 2007 there were outstanding 10,132,826 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 1, 2007 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.

FORM 10-K - 2006

TABLE OF CONTENTS

PART I

Item 1. Business

(a) General Description of Business

Central Vermont Public Service Corporation (the "Company" or "we" or "our"), incorporated under the laws of Vermont on August 20, 1929, is engaged in the purchase, production, transmission, distribution and sale of electricity. The Company is the largest electric utility in Vermont, serving about 155,000 retail customers in nearly three-quarters of the towns, villages and cities in Vermont. The Company's wholly owned subsidiaries include:

- Custom Investment Corporation ("Custom"), which was formed for the purpose of holding passive investments, including the stock of the Company's subsidiaries that invest in regulated business opportunities. On October 13, 2003, the Company transferred its shares of Vermont Yankee Nuclear Power Corporation ("VYNPC") to Custom. The transfer to Custom does not affect the Company's rights and obligations related to VYNPC.
- C.V. Realty, Inc., a real estate company whose purpose is to own, acquire, buy, sell and lease real and personal property and interests therein related to the utility business.
- Central Vermont Public Service Corporation - East Barnet Hydroelectric, Inc. which was created for the purpose of financing and constructing a hydroelectric facility in Vermont, which became operational September 1, 1984 and has been leased and operated by the Company since its in-service date.
- Connecticut Valley Electric Company Inc. ("Connecticut Valley"), incorporated under the laws of New Hampshire on December 9, 1948, distributed and sold electricity in parts of New Hampshire bordering the Connecticut River. On January 1, 2004, Connecticut Valley completed the sale of substantially all of its plant assets and its franchise to Public Service Company of New Hampshire. Connecticut Valley no longer conducts business as an electric utility in New Hampshire.
- Catamount Resources Corporation ("CRC") formed for the purpose of holding the Company's subsidiaries that invest in unregulated business opportunities. CRC's wholly owned subsidiary, Eversant Corporation, engages in the sale or rental of electric water heaters through a wholly owned subsidiary, SmartEnergy Water Heating Services, Inc. to customers in Vermont and New Hampshire. CRC had a wholly owned subsidiary, Catamount Energy Corporation ("Catamount") that invested primarily in wind energy in the United States and the United Kingdom. In December 2005, CRC completed the sale of all of its interest in Catamount to CEC Wind Acquisition, LLC, a Delaware limited liability company established by Diamond Castle Holdings ("Diamond Castle").

The Company's equity ownership interests as of December 31, 2006 are summarized below. These are also described in more detail in Part II, Item 8, Note 4 - Investments in Affiliates.

- The Company owns 58.85 percent of the common stock of VYNPC, which was initially formed by a group of New England utilities for the purpose of constructing and operating a nuclear-powered generating plant in Vernon, Vermont. On July 31, 2002, VYNPC sold the plant to Entergy Nuclear Vermont Yankee, LLC ("ENVY"). The sale agreement included a purchased power contract ("PPA") between VYNPC and ENVY. Under the PPA, VYNPC pays ENVY for generation at fixed rates, and in turn, bills the PPA charges from ENVY with certain residual costs of service through a FERC tariff to the Company and the other VYNPC sponsors.
- The Company owns 47.05 percent of the common stock and 48.03 percent of the preferred stock of Vermont Electric Power Company, Inc. ("VELCO"), which owned the high-voltage transmission system in Vermont. In June 2006, VELCO transferred substantially all of its business operations to Vermont Transco LLC ("Transco"). VELCO has a 30.8 percent equity interest in Transco and manages the operations of Transco under a Management Services Agreement. VELCO's wholly owned subsidiary, Vermont Electric Transmission Company, Inc. ("VETCO"), 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 New England.
- The Company owns 29.86 percent of Class A Units of Transco, which was formed by VELCO and its owners in the second quarter of 2006. Transco now owns and operates the high-voltage transmission system in Vermont. VELCO and its employees now manage the operations of Transco under a Management Services Agreement between VELCO and Transco. The Company's total direct and indirect interest in Transco is 44.34 percent.
- The Company owns 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 or are nearing completion of decommissioning.

The Company also owns small generating facilities and has joint ownership interests in certain generating facilities. These are described in Sources and Availability of Power Supply below.

(b) Financial Information about Industry Segments
The Company's principal operating segments are the regulated utility business and its non-regulated businesses. See Part II Item 8, Note 18 - Segment Reporting for financial information regarding the Company's operating segments.

(c) Narrative Description of Business
Principal Products and Services
The Company's operating revenues consist primarily of retail and resale sales. Retail sales are comprised of a diversified customer mix including residential, commercial and industrial customers. Sales to the five largest retail customers receiving electric service from the Company accounted for about 6 percent of the Company's annual retail electric revenues for 2006, 2005 and 2004. Resale sales are related to 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. The Company's operating revenues and energy sales as of December 31 consisted of the following:

	Revenue			mWh Sales		
	2006	2005	2004	**2006**	2005	2004
Retail Sales:						
Residential	**38%**	41%	42%	**29%**	33%	34%
Commercial	**32%**	33%	34%	**27%**	31%	31%
Industrial and other	**12%**	12%	12%	**13%**	14%	15%
Resale Sales	**16%**	13%	9%	**31%**	22%	20%
Customer refund	**-**	(2%)	-	**-**	-	-
Other operating revenue	**2%**	3%	3%	**-**	-	-

Retail Rates The Company's retail rates are set by the Vermont Public Service Board ("PSB") after considering recommendations of Vermont's consumer advocate, the Vermont Department of Public Service ("DPS"). While the Company's retail rates do not have fuel or power cost adjustment mechanisms, the PSB has previously approved the deferral of extraordinary costs incurred that might normally be expensed by unregulated businesses in order to match these expenses with future revenues. Fair regulatory treatment is fundamental to maintaining the Company's financial stability. Rates must be set at levels to recover costs, including a market rate of return to equity and debt holders, in order to attract capital.

The Company's retail rates at December 31, 2006 are based on a March 29, 2005 PSB Order that included, among other things: 1) a 2.75 percent rate reduction beginning April 1, 2005; 2) a $6.5 million pre-tax refund to customers; 3) a 10 percent return on equity (reduced from 11 percent); and 4) a requirement that the gain related to the 2004 Connecticut Valley sale be applied to the benefit of ratepayers to compensate for increased costs. This resulted in a $21.8 million pre-tax charge to utility earnings in the first quarter of 2005. On June 22, 2005, the Company filed an appeal of portions of the PSB's Order with the Vermont Supreme Court. The issues that were raised on appeal primarily focused on whether the 2005 Rate Order set rates retroactively without statutory authorization. On July 18, 2006, the Court issued its decision rejecting the Company's appeal. The Court's decision had no effect on the Company's financial condition or results of operations for 2006.

On May 15, 2006, the Company filed a request for a 6.15 percent rate increase (additional revenue of $16.4 million on an annual basis), to be effective February 1, 2007. On September 11, 2006, the Company and the DPS reached a settlement in the case, agreeing to a 3.73 percent increase effective January 1, 2007. The agreement reduced the Company's proposed allowed rate of return on common equity from 12 percent to 10.75 percent. On November 6, 2006, the Company and DPS filed amended testimony with the PSB to settle the Company's Accounting Order request related to recovery of fourth quarter 2005 replacement energy costs associated with a Vermont Yankee scheduled refueling outage. The agreement included recovery of incremental replacement energy costs of $1.5 million over a two-year period and added 0.34 percent to the Company's rate increase request, resulting in a combined rate increase request of 4.07 percent effective January 1, 2007.

On December 7, 2006, the PSB issued an Order ("2006 Rate Order") approving the 4.07 percent rate increase effective January 1, 2007. The 2006 Rate Order provided, among other things, an allowed rate of return on common equity of 10.75 percent capped until the Company's next rate proceeding. The January 1, 2007 rate increase, net of amounts to be returned to customers as described below, will add revenue of approximately $9.9 million annually.

The Company's Accounting Order request for recovery of $1.5 million of incremental replacement power costs described above was subject to PSB approval. The 2006 Rate Order requires the Company to record a regulatory asset or liability for any difference between the replacement power cost amortization included in the 4.07 percent rate increase and the amount approved by the PSB. On January 12, 2007, the PSB issued an Order denying the Company's Accounting Order request. This 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. Instead, the Company will defer the $1.5 million of revenue over two years and continue such deferral until its next rate proceeding, at which time the total amount deferred will be returned to customers.

Wholesale Rates The Company provides wholesale transmission service to nine 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). The Company also provides wholesale transmission service to one network customer under one FERC rate schedule. The Company maintains an OASIS site for transmission on the ISO-New England web page. The Company also provides wholesale power service to Woodsville Fire District Water and Light Department under FERC Electric Tariff, Original Volume No. 5.

Sources and Availability of Power Supply

The Company's energy generation and purchased power required to serve retail and firm wholesale customers was 2,461,444 mWh for the year ended December 31, 2006. The maximum one-hour integrated demand during that period was 437.6 MW and occurred on August 2, 2006. For 2005, the Company's energy generation and purchased power required to serve retail and firm wholesale customers was 2,488,790 mWh. The maximum one-hour integrated demand was 412.0 MW and occurred on July 19, 2005. The sources of energy and capacity available to the Company for the year ended December 31, 2006 follows:

	Net Effective Capability 12 Month Average MW	Generated and Purchased mWh	%
Wholly Owned Plants:			
Hydro	41.2	235,464	6.8
Diesel and Gas Turbine	27.3	615	-
Jointly Owned Plants:			
Millstone #3	20.0	174,540	5.1
Wyman #4	10.7	905	-
McNeil	10.7	52,908	1.5
Long-Term Purchases:			
VYNPC	179.6	1,689,390	49.1
Hydro-Quebec	142.9	998,365	29.0
Independent power producers	33.5	198,735	5.8
Other Purchases:			
System and other purchases	0.4	22,961	0.7
NEPOOL (ISO-New England)	-	67,479	2.0
Total	466.3	3,441,362	100.0

Wholly Owned Plants: The Company's wholly owned plants are located in Vermont, and have a combined nameplate capacity of about 74.2 MW. The Company operates 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.

Jointly Owned Plants: The Company's joint-ownership interests in generating and transmission plants are shown in the table below. The Company is responsible for its share of the operating expenses of these facilities (dollars in thousands).

	Fuel Type	Ownership	In Service Date	MW Entitlement	December 31 2006	2005
Wyman #4	Oil	1.7769%	1978	10.8	**$3,422**	$3,419
Joseph C. McNeil	Various	20.0000%	1984	10.8	**15,555**	15,575
Millstone Unit #3	Nuclear	1.7303%	1986	20.0	**77,162**	77,105
Highgate Transmission Facility		47.5200%	1985	N/A	**14,357**	14,302
					110,496	110,401
Less accumulated depreciation					**60,986**	58,141
					$49,510	$52,260

The Company receives its share of output and capacity of Millstone Unit #3, a 1,155 MW nuclear generating facility; Wyman #4, a 609 MW generating facility and Joseph C. McNeil, a 54 MW generating facility, as shown in the sources and availability of power supply table above.

The Highgate Converter, a 225 MW facility, 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.

Major Long-Tem Purchases:
Vermont Yankee: The Company purchases its entitlement share of Vermont Yankee plant output from VYNPC under a purchased power contract ("PPA") between VYNPC and ENVY. The PPA extends through the plant's current license life which expires in 2012. On June 8, 2006, the plant received a new output rating of approximately 620 MW, a 20 percent increase in plant capacity. The Company's entitlement of total plant output was reduced from 35 percent to 29 percent in September 2006 due to the uprate, but its share of plant output is similar to the amount received before the uprate process began. Prices under the PPA range from $39 to $45 per megawatt hour. 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. If market prices rise, however, PPA prices are not adjusted upward in excess of the PPA price.

ENVY has no obligation to supply energy to VYNPC over the amount the plant is producing, so the Company receives reduced amounts when the plant is operating at a reduced level, and no energy when the plant is not operating. The Company is responsible for purchasing replacement energy at these times. The next refueling outage is scheduled to begin in May 2007. The Company has entered into a forward purchase contract for the purchase of replacement energy during the scheduled outage. The Company also purchased forced outage insurance to cover additional costs, if any, of obtaining replacement power from other sources if Vermont Yankee experiences unplanned outages between January 1 and December 31, 2007.

If the Vermont Yankee plant is shut down for any reason prior to the end of its operating license, the Company would lose about 50 percent of its committed energy supply and would have to acquire replacement power resources for approximately 40 percent of its estimated power supply needs. The Company is not able to predict whether there will be an early shutdown of the Vermont Yankee plant or whether the PSB will allow timely and full recovery of increased costs related to any such shutdown. However, an early shutdown could materially impact the Company's financial position and future results of operations if the costs are not recovered in retail rates in a timely fashion.

Hydro-Quebec: The Company is 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 the Company. The VJO Power Contract has been in place since 1987 and purchases began in 1990. Related contracts were subsequently negotiated between the Company and Hydro-Quebec, which 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 the Company's purchases under the contract end in 2016. As of December 31, 2006, the Company's obligation is about 47 percent of the total VJO Power Contract through 2016. The average annual amount of capacity that the Company will purchase from January 1, 2007 through October 31, 2012 is about 145.3 MW, with lesser amounts purchased through October 31, 2016.

In 1994, the Company negotiated a sellback arrangement whereby it 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 deliveries by 50 MW beginning as early as 2010, 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 load factor of 75 to 50 percent due to adverse hydraulic conditions as measured at certain agreed upon metering stations on regulated and unregulated rivers in Quebec. This second option can be exercised five times through October 2015. Hydro-Quebec has not yet exercised these options.

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, and Hydro-Quebec had elections to reduce the load factor to not less than 65 percent three times during the same period of time. Hydro-Quebec has used all of its elections, resulting in a 65 percent load factor obligation from November 1, 2002 to October 31, 2005. The VJO elected to purchase at an 80 percent load factor for the contract year beginning November 1, 2005, and made a similar election for the contract year beginning November 1, 2006. The VJO have now used all of their load factor elections. After the contract year ending October 31, 2007, the annual load factor will be at 75 percent for the remainder of the contract, unless all parties agree to change it or there is a reduction due to the hydraulic conditions described above.

Independent Power Producers: The Company purchases power from several Independent Power Producers ("IPPs") who own qualifying facilities under the Public Utilities Regulatory Policies Act of 1978. These facilities primarily use water and biomass as fuel. Most of the power comes through a state-appointed purchasing agent, which assigns power to all Vermont utilities under PSB rules. In 2006, power purchases from IPPs amounted to 6.7 percent of total mWh purchased and 19.2 percent of purchased power expense.

See Part II, Item 7, Power Supply Matters, and Item 8, Note 17 - Commitments and Contingencies, for additional information.

Other Purchases:
System and Other Purchases, including ISO-New England: The Company participates 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"). The Company also engages in short-term purchases with other third parties, primarily in New England, to minimize net power costs and risks to its customers. The Company enters into forward purchase contracts when additional supply is needed and enters into forward sale contracts when it forecasts excess supply. On an hourly basis, power is sold or bought through ISO-New England's settlement process to balance the Company's resource output and load requirements. On a monthly basis, the Company aggregates the hourly sales and purchases through ISO-New England and records them as operating revenue or purchased power, respectively.

See Part II, Item 7, Power Supply Matters and Wholesale Market and Transmission Matters, for additional information related to sources and availability of power supply.

Franchise

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

An amendment to 30 V.S.A. Section 212(a) enacted May 28, 1987 authorizes the Vermont Department of Public Service ("DPS") to purchase and distribute power at retail to all consumers of electricity in Vermont, subject to certain preconditions specified in new 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 they are 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 sixty (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 the Company's service area since 1993.

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

There have been two instances where Chapter 79 of Title 30 has been invoked. In one instance, the Town of Springfield acted to acquire the Company's distribution facilities in that community pursuant to a vote in 1977; that action was discontinued in 1985. The other instance, which occurred in 2002, involved the Town of Rockingham, which voted to pursue purchase of the Company's distribution facilities, Green Mountain Power's ("GMP") distribution facilities, and another party's hydroelectric facility located in Bellows Falls. The Company and GMP refused to voluntarily sell their distribution facilities. In November 2003, the Company was notified that Rockingham intended to obtain their facilities by eminent domain under Title 24 V.S.A. Section 2805. The Company opposed this action as being contrary to Title 30, and in December 2003 obtained a permanent injunction from the Superior Court prohibiting Rockingham from pursuing this course of action. If Rockingham decides to continue this action in the future, it must proceed with the PSB under Title 30. After its option to purchase the Bellows Falls hydroelectric facility expired in 2005, Rockingham discontinued its efforts to acquire the Company's distribution facilities.

Utility Acquisitions: In 2006, the Company purchased the plant assets and franchises of Rochester Electric Light and Power Company and the southern Vermont franchise territory and related plant assets of Vermont Electric Cooperative. These purchases added approximately 3,600 to the Company's customer base.

Regulation

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

Federal Power Act: Certain phases of the businesses of the Company and Transco, including certain rates, are subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC") as follows: the Company as a licensee of hydroelectric developments under Part I of the Federal Power Act, and the Company and Transco as interstate public utilities under Parts II and III, as amended and supplemented by the National Energy Act. The Company is in the process of relicensing or preparing to relicense six separate hydro-projects under the Federal Power Act. These projects, some of which are grouped together under a single license, represent about 24.5 MW, or 54.8 percent, of the Company's hydroelectric nameplate capacity. The Company has obtained an exemption from licensing for the Bradford and East Barnet projects.

Federal Energy Policy Act of 2005: The Federal Energy Policy Act of 2005 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. The Company, by reason of its ownership of utility subsidiaries, is a holding company, as defined in the Public Utility Holding Company Act of 2005.

Nuclear Regulatory Commission ("NRC"): The nuclear generating facilities in which the Company has 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.

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 State and a large abutting multi-state region referred to as PJM. At the retail level, customers have long had energy options such as propane, natural gas or oil for heating, cooling and water heating, and self-generation. Another competitive threat is the potential for customers to form municipally owned utilities in the Company's service territory.

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.

Environmental Matters

The Company is subject to environmental regulations in the licensing and operation of the generation, transmission, and distribution facilities in which it has an interest, as well as the licensing and operation of the facilities in which it is a co-licensee. These environmental regulations are administered by local, state and federal regulatory authorities and may impact the Company's generation, transmission, distribution, transportation and waste handling facilities on air, water, land and aesthetic qualities.

The Company cannot presently forecast the costs or other effects that environmental regulation may ultimately have on its existing and proposed facilities and operations. The Company believes that any such prudently incurred costs related to its utility operations would be recoverable through the ratemaking process. For additional information see Part II, Item 8, Note 17 - Commitments and Contingencies, herein for disclosures relating to environmental contingencies, hazardous substance releases and the control measures related thereto.

Seasonal Nature of Business

The Company's 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 little heating or cooling load.

Capital Expenditures

The Company's business is capital-intensive and requires annual construction expenditures to maintain the distribution system. The Company's capital expenditures for the next five years are estimated to be $33.0 million in 2007, $27.5 million in 2008, $22.5 million in 2009, $35.0 million in 2010 and $40.6 million in 2011. These are subject to continuing review and adjustment and actual capital expenditures may vary. Also see Part II, Item 7, Liquidity, Capital Resources and Commitments.

Number of Employees
Local Union No. 300, affiliated with the International Brotherhood of Electrical Workers, represents operating and maintenance employees of the Company. On December 31, 2006 the Company had 535 employees, of which 222 are represented by the union. On December 29, 2004, the Company and its employees represented by the union agreed to a new four-year contract, which expires on December 31, 2008. The new contract provided for a net general wage increase of 3.5 percent effective January 2, 2005, January 1, 2006, December 31, 2006 and December 30, 2007.

Executive Officers of Registrant
The following sets forth the present Executive Officers of the Company. 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, 59	President and Chief Executive Officer	1987
William J. Deehan, 54	Vice President - Power Planning and Regulatory Affairs	1991
Brian P. Keefe, 49	Vice President - Governmental Affairs	2006
Pamela J. Keefe, 41	Vice President, Chief Financial Officer, and Treasurer	2006
Joan F. Gamble, 49	Vice President - Strategic Change and Business Services	1998
Joseph M. Kraus, 51	Senior Vice President - Operations, Engineering and Customer Service	1987
Dale A. Rocheleau, 48	Senior Vice President for Legal and Public Affairs, and Corporate Secretary	2003

Mr. Young joined the Company in 1987. He was elected Senior Vice President - Finance and Administration in 1988. He served as Executive Vice President and Chief Operating Officer (COO) commencing in 1993 and was elected Director, President and Chief Executive Officer (CEO) commencing in 1995. Mr. Young also serves as President, CEO, and Chair of the following CVPS subsidiaries: Connecticut Valley Electric Company Inc.; CVPSC - East Barnet Hydroelectric, Inc.; CV Realty, Inc.; Custom Investment Corporation; Catamount Resources Corporation; Eversant Corporation; and, SmartEnergy Water Heating Services, Inc. He is also Director of the following CVPS affiliates: Vermont Electric Power Company, Inc., Vermont Yankee Nuclear Power Corporation; Vermont Electric Transmission Company, Inc.; and, The Home Service Store, Inc.

Mr. Deehan joined the Company in 1985 with nine years of utility regulation and related research experience. Prior to being elected to his present position in May 2001, he served as Vice President - Regulatory Affairs and Strategic Analysis. He previously served as Assistant Vice President - Rates and Economic Analysis from April 1991 to May 1996. From 1988 to 1991 he served as Director of Rate Administration and Forecasting for the Company.

Ms. Gamble joined the Company in 1989 with 10 years of electric utility and related consulting experience. Since joining the Company, she has held a variety of positions with increasing responsibility. Ms. Gamble was elected to her present position in August 2001. Ms. Gamble also serves as Vice President - Strategic Change and Business Services for the following CVPS subsidiary: Eversant Corporation. She serves as a Director for the following CVPS subsidiaries: Eversant Corporation and SmartEnergy Water Heating Services, Inc.

Mr. Keefe joined the Company in December 2006. 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. In 1998 and 1999, he served as a policy coordinator for the Vermont Electricity Consumers Coalition, an association of Vermont businesses, business organizations and residential groups working to mitigate high electricity costs. Mr. Keefe worked for Sen. Jeffords in Washington, D.C., from 1988 to 1992, where he managed such legislation as the Clean Air Amendments of 1991, the Oil Spill Prevention Act and the Intermodal Surface Transportation Act. From 1993 to 1998, he served on Sen. Jeffords' Vermont staff, with primary responsibilities in the areas of energy, environment and natural resources.

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 the following CVPS subsidiaries: Connecticut Valley Electric Company Inc.; CVPSC - East Barnet Hydroelectric, Inc.; CV Realty, Inc.; and, Catamount Resources Corporation. She also serves as a Director of Vermont Yankee Nuclear Power Corporation, a CVPS affiliate.

Mr. Kraus joined the Company in 1981. Prior to being elected to his present position of Senior Vice President Operations, Engineering and Customer Service, he served as Senior Vice President Engineering and Operations, General Counsel, and Secretary from May 2003 until November 2003. He previously served as Senior Vice President Customer Service, Secretary, and General Counsel from May 2001 to May 2003. Mr. Kraus serves as Director of the following CVPS subsidiaries: Connecticut Valley Electric Company Inc.; CVPSC - East Barnet Hydroelectric, Inc.; CV Realty, Inc.; Custom Investment Corporation; Catamount Resources Corporation; Eversant Corporation; and, SmartEnergy Water Heating Services, Inc.

Mr. Rocheleau joined the Company in November 2003 as Senior Vice President for Legal and Public Affairs, and Corporate Secretary. 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 for Legal and Public Affairs and Corporate Secretary of the following CVPS subsidiaries: Connecticut Valley Electric Company Inc.; CVPSC - East Barnet Hydroelectric, Inc.; CV Realty, Inc.; Custom Investment Corporation; Catamount Resources Corporation; 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, began operation in January 2000. The Company has a continuing obligation to provide customer information and referrals, coordination of customer service, power quality, and any other distribution utility functions, which may intersect with the EEU's utility activities.

The Company has retained the obligation to deliver demand side management programs targeted at deferral of its transmission and distribution projects, known as Distributed Utility Planning ("DUP"). DUP is designed to ensure that delivery services are provided at least cost and to create the most efficient transmission and distribution system possible. The PSB is currently considering a similar DUP process for the bulk transmission lines and Transco.

Nuclear Decommissioning Obligations

The Company has a 1.7303 joint-ownership percentage in Millstone Unit # 3. As a joint owner, in which Dominion Nuclear Corporation ("DNC") is the lead owner with about 93.4707 percent of the plant joint-ownership, the Company is responsible for its share of nuclear decommissioning costs. The Company has an external trust dedicated to funding its joint-ownership share of future decommissioning costs. DNC has suspended contributions to the Millstone Unit #3 Trust Fund because the minimum NRC funding requirements are being met or exceeded. The Company has also suspended contributions to the Trust Fund, but could choose to renew funding at its own discretion as long as the minimum requirement is met or exceeded. If a need for additional decommissioning funding is necessary, the Company will be obligated to resume contributions to the Trust Fund.

The Company owns, through equity investments, 2 percent of Maine Yankee, 2 percent of Connecticut Yankee and 3.5 percent of Yankee Atomic, and is responsible for paying its equity ownership percentage of decommissioning costs and all other costs for these plants. As of December 31, 2006, based on the most recent estimates provided, the Company's share of remaining costs to decommission these three nuclear units is $3.4 million for Maine Yankee, $8.2 million for Connecticut Yankee and $3.3 million for Yankee Atomic.

See Part II, Item 7, Nuclear Generating Companies, and Item 8, Note 4 - Investments in Affiliates for additional information.

Unregulated Businesses

CRC's wholly owned subsidiary, Eversant Corporation, engages in the sale or rental of electric water heaters through a wholly owned subsidiary, SmartEnergy Water Heating Services, Inc. to customers in Vermont and New Hampshire. On December 20, 2005, CRC sold all of its interest in Catamount to Diamond Castle. Cash proceeds from the sale amounted to $59.25 million, resulting in an after-tax gain of $5.6 million. See Part II, Item 8, Note 5 - Discontinued Operations.

Repurchase of Common Stock

On February 7, 2006, the Company's Board of Directors authorized the repurchase of 2,250,000 shares of the Company's common stock in a reverse Dutch tender offer using proceeds from the December 20, 2005 sale of Catamount. Under the procedures of the tender offer, shareholders could offer to sell some or all of their stock to the Company at a target price in a range from $20.50 to $22.50 per share. The tender offer commenced on February 14, 2006 and ended on April 5, 2006. Upon conclusion of the tender offer, the Company purchased 2,249,975 shares, about 18.3 percent of its common shares outstanding, at $22.50 per share. Cash paid for the common shares including transaction costs, amounted to $51.2 million.

Recent Energy Initiatives

The State of Vermont continues to examine changes to the provision of electric service absent introduction of retail choice. Several laws have been passed since 2005 that impact electric utilities in Vermont. These include: 1) Act 61 - Renewable Energy, Efficiency, Transmission, and Vermont's Energy Future; 2) Act 208 - Vermont Energy Security and Reliability Act; and 3) Act 123 - Regional Greenhouse Gas Initiative. While provisions of recently passed laws are now being implemented, the 2007 Legislature continues to deliberate new policies designed to reduce electricity consumption, promote renewable energy and reduce greenhouse gas emissions. See Part II, Item 7, Recent Energy Initiatives for more detail.

(d) Financial Information about Geographic Areas

The Company and its subsidiaries do not have any foreign operations or export sales.

(e) Available Information

The Company makes available free of charge through its Internet Website, *www.cvps.com* its 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 Website through "Investor Relations." The Company's Corporate Ethics and Conflict of Interest Policy, Corporate Governance Guidelines, and Charters of the Audit, Compensation and Corporate Governance Committees are also available on its Internet Website. Access to these documents is available from the main page of the Internet Website through "Corporate Governance and Ethics." Printed copies of these documents are also available upon written request to the Assistant Corporate Secretary at its principal executive offices. The Company's reports, proxy, information statements and other information are also available by accessing the SEC's Internet Website, *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-SEC-0330.

Item 1A. Risk Factors

We regularly identify, monitor and assess our exposure to risk and seek to mitigate the risks inherent in our energy business. However, there are risks that are beyond our control or that cannot be limited cost-effectively or that may occur despite our risk mitigation strategies. The risk factors discussed below could have a material effect on our financial position, results of operations or cash flows.

Risks related to timing and adequacy of rate relief: We are regulated by the PSB, the Connecticut Department of Public Utility Control and FERC, with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. Electric utilities are subject to certain accounting standards that apply only to regulated businesses. We prepare our financial statements in accordance with Statement of Financial Accounting

Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71"), for our regulated Vermont service territory and FERC-regulated wholesale business. 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 about $19.9 million on a pre-tax basis as of December 31, 2006, assuming no stranded cost recovery would be allowed through a rate mechanism. We would also be required to record pension and postretirement costs of $31.7 million on a pre-tax basis to Accumulated Other Comprehensive Loss as a reduction in stockholder's 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.

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. Our retail rates do not have fuel or power cost adjustment mechanisms that would allow increases in power supply costs to be recovered immediately in the rates we charge customers. Obtaining a change in retail rates generally requires a rate proceeding that could last up to nine months. In December 2006, the PSB approved a rate increase effective January 1, 2007, and we are planning to request an additional rate increase later in 2007.

Vermont law also allows electric utilities to seek temporary rate increases if deemed necessary by the PSB to provide adequate and efficient service or to preserve the viability of the utility. Additionally, Vermont law permits alternative regulation that could potentially provide mechanisms to adjust rates for changes in power supply expense, if approved by the PSB. Recently the PSB approved an alternative regulation plan proposed by another Vermont utility. We are evaluating that plan to determine whether to seek approval of an acceptable alternative regulation plan for our business.

Risks related to our current credit rating, which is below investment grade: In June 2005, Standard & Poor's Ratings Services ("S&P") lowered our corporate credit rating to below investment grade. We believe that restoration of our credit rating is critical to the long-term success of the Company. While our credit rating remains below investment-grade, the cost of capital, which is ultimately passed on to our customers, will be greater than it otherwise would be. That, combined with other 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 VYNPC begin to expire five to six 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, but we don't anticipate any constraints on access to capital in the near term.

Risks related to our power supply and wholesale power market prices: Our material power supply contracts are principally with Hydro-Quebec and VYNPC. The power supply contracts with VYNPC and Hydro-Quebec comprise the majority of our total annual energy (mWh) purchases. 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 potential high cost of replacement power and performance assurance collateral requirements arising from purchases through ISO-New England or third parties. We could seek emergency rate relief from our regulators if this occurred.

Our contract for power purchases from VYNPC ends in 2012, but there is a risk that the plant could be shut down earlier than expected if ENVY 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 be reduced in 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.

Risks related to liquidity: We believe that cash on hand, cash flow from operations and our $25.0 million credit facility will be sufficient to fund our business. Based on our current cash forecasts, we believe the borrowing capacity under the credit facility will provide sufficient liquidity at least until the end of 2007, and possibly longer. However, an extended 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. 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 described below, primarily as a result of high power market prices.

Risks related to the economic condition of our customers: An economic downturn and increased cost of energy supply could adversely affect energy consumption and therefore impact our results of operations. Energy consumption is significantly impacted by the general level of economic activity and cost of energy supply. 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. A recession or prolonged lag of a subsequent recovery could have an adverse effect on our results of operations, cash flows or financial position.

Item 1B. Unresolved Staff Comments

None

Item 2. Properties

The Company's properties are operated as a single system that is interconnected by the transmission lines of VELCO, New England Power and Public Service Company of New Hampshire. The Company owns and operates 23 small generating stations with a total current nameplate capability of 73.6 MW. The Company's 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.

The electric transmission and distribution systems of the Company include about 616 miles of overhead transmission lines, about 8,333 miles of overhead distribution lines and about 418 miles of underground distribution lines, all of which are located in Vermont except for about 23 miles in New Hampshire and about 2 miles in New York.

All of the principal plants and important units of the Company and its subsidiaries are held in fee. 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 so located pursuant to authority conferred on public utilities by statute, subject to regulation of state or municipal authorities.

Additional information with respect to the Company's properties is set forth under Part I, Item 1, Sources and Availability of Power Supply and is incorporated herein by reference.

Substantially all of the Company's utility property and plant is subject to liens under the Company's First Mortgage Indenture.

Transco's properties consist of about 614 miles of high voltage overhead and underground transmission lines and associated substations. The lines connect on the west with the lines of Niagara Mohawk Power Corporation at the Vermont-New York state line near Whitehall, New York, and Bennington, Vermont, and with the submarine cable of NYPA near Plattsburgh, New York; on the south and east with the lines of New England Power Company and PSNH; on the south with the facilities of Vermont Yankee; and on the northern border of Vermont with the lines of Hydro-Quebec near Derby and through the Highgate converter station and tie line jointly owned by the Company and several other Vermont utilities.

VETCO has about 52 miles of high voltage DC transmission line connecting with the transmission line of Hydro-Quebec at the Quebec-Vermont border in the Town of Norton, Vermont; 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 hydro-electric generating station.

Item 3. Legal Proceedings

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

Item 4. Submission of Matters to a Vote of Security Holders
There were no matters submitted to security holders during the fourth quarter of 2006.

PART II

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

(a) The Company's common stock is listed on the New York Stock Exchange ("NYSE") under the trading symbol CV. Newspaper listings of stock transactions use the abbreviation CVtPS or CentlVtPS and the Internet trading symbol is CV.

The table below shows the high and low sales price of the Company's 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	
	High	Low
2006		
First Quarter	$ 21.95	$ 17.89
Second Quarter	21.90	16.11
Third Quarter	23.00	18.01
Fourth Quarter	23.92	20.94
2005		
First Quarter	$ 23.69	$ 21.80
Second Quarter	22.75	18.02
Third Quarter	19.76	17.23
Fourth Quarter	21.68	15.27

(b) As of December 31, 2006, there were 6,960 holders of the Company's Common Stock, $6 par value.

(c) Common Stock dividends have been declared quarterly. Cash dividends of $0.23 per share were paid for all quarters of 2006 and 2005.

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 the Company's Articles of Association; such definitions are based upon the unconsolidated financial statements of the Company. As of December 31, 2006, the Common Stock Equity of the unconsolidated Company was 56.1 percent of total capitalization.

The Company's 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 Net Income of the Company (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 the unconsolidated financial statements of the Company. As of December 31, 2006, $49.1 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.

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

	2006	2005	2004	2003	2002
Income Statement					
Operating revenues	**$325,738**	$311,359	$302,286	$306,098	$294,390
Income from continuing operations (a)	**$18,101**	$1,410	$7,493	$17,148	$17,414
Income from discontinued operations (b)	**251**	4,936	16,262	2,653	1,543
Net income	**$18,352**	$6,346	$23,755	$19,801	$18,957
Per Common Share Data					
Basic earnings from continuing operations	**$1.65**	$0.09	$0.59	$1.35	$1.49
Basic earnings from discontinued operations	**.02**	0.40	1.34	0.22	0.13
Basic earnings per share	**$1.67**	$0.49	$1.93	$1.57	$1.62
Diluted earnings from continuing operations	**$1.64**	$0.08	$0.58	$1.32	$1.46
Diluted earnings from discontinued operations	**.02**	0.40	1.32	0.21	0.13
Diluted earnings per share	**$1.66**	$0.48	$1.90	$1.53	$1.59
Cash dividends declared per share of common stock	**$0.69**	$1.15	$0.92	$0.88	$0.88
Balance Sheet					
Long-term debt (c)	**$115,950**	$115,950	$115,950	$115,950	$127,108
Capital lease obligations (c)	**$6,612**	$6,153	$7,094	$8,115	$11,762
Redeemable preferred stock (c)	**$3,000**	$4,000	$6,000	$8,000	$10,000
Total capitalization (c)	**$312,968**	$351,527	$361,751	$350,560	$354,532
Total assets	**$500,938**	$551,433	$563,389	$534,635	$546,685

(a) For 2005 includes a $21.8 million pre-tax charge to earnings ($11.2 million after-tax) related to the 2005 Rate Order described in Part II, Item 8, Note 8 - Retail Rates and Regulatory Accounting. For 2004 includes a $14.4 million pre-tax charge to earnings ($8.9 million after-tax) related to termination of the 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, 2003 and 2002 includes Catamount and Connecticut Valley. See Part II, Item 8, Note 5 - Discontinued Operations.

(c) Amounts exclude current portions.

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

In this section we discuss the general financial condition and results of operations for Central Vermont Public Service Corporation (the "Company" or "we" or "our" or "us") and its subsidiaries. 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.

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

- the actions of regulatory bodies;
- performance of the Vermont Yankee nuclear power plant;
- effects of and changes in weather and economic conditions;
- volatility in wholesale power markets;
- ability to maintain or improve our current credit ratings; and
- other considerations such as the operations of ISO-New England, changes in the cost or availability of capital, authoritative accounting guidance and the effect of the volatility in the equity markets on pension benefit and other costs.

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

EXECUTIVE SUMMARY

Our consolidated 2006 earnings were $18.4 million, or $1.66 per diluted share of common stock, compared to 2005 earnings of $6.3 million, or 48 cents per diluted share of common stock, and 2004 earnings of $23.8 million, or $1.90 per diluted share of common stock. The primary drivers of consolidated earnings for the past three years are discussed in detail in Results of Operations.

Our primary focus in 2006 has been on continuing to restore the Company's financial strength following an adverse rate order in 2005 and a downgrade of our corporate credit rating to below investment grade. In December 2006, the PSB approved a retail rate increase effective January 1, 2007 as described in Retail Rates below. We are planning to request an additional rate increase in 2007.

We made significant cash investments, in addition to our own capital improvements, during 2006 including:

- In March, we made additional contributions of $12.2 million to our pension fund and $4.1 million to our postretirement medical fund. We used cash on hand and available-for-sale securities to fund these contributions.
- In April, we purchased approximately 2.25 million shares of our common stock for $22.50 per share using approximately $51.2 million of cash proceeds from the 2005 sale of Catamount Energy Corporation ("Catamount"). The stock buyback decreased common shares outstanding by approximately 18 percent.
- In June, we invested $8.9 million in Vermont Transco LLC ("Transco"), a Vermont limited liability company formed by Vermont Electric Power Company, Inc. ("VELCO") and its owners, including us. We invested an additional $14.4 million in the third quarter, for a total investment in Transco of $23.3 million. Our direct interest is currently at 29.86 percent and earns an allowed rate of return of 11.5 percent. We also have a 14.48 percent indirect interest in Transco through our ownership interest in VELCO. In total our direct and indirect interest in Transco is 44.34 percent. We used cash on hand and available-for-sale securities to fund our investments in Transco. See Liquidity and Capital Resources for additional information.

COMPANY OVERVIEW

We are a Vermont-based electric utility that transmits, distributes and sells electricity. We are regulated by the Vermont Public Service Board ("PSB"), the Connecticut Department of Public Utility Control and the FERC, with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. The Vermont utility operation is our core business. We had previously owned a small regulated electric utility in New Hampshire, Connecticut Valley Electric Company ("Connecticut Valley"), but it sold substantially all of its plant assets and franchise on January 1, 2004.

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 does not represent a significant business activity for us. CRC had a wholly owned subsidiary, Catamount Energy Corporation ("Catamount"), which invested primarily in wind energy in the United States and the United Kingdom, but that business was sold on December 20, 2005.

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 small acquisitions or growth within the service territory. In 2006, we added approximately 3,600 customers to our service territory through two small acquisitions. Given the nature of our customer base, weather and economic conditions are factors that can significantly affect our 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 slight decreases in some years to increases of 2 percent in others. We currently have sufficient power resources to meet our forecasted load requirements through 2011, mostly through power supply contracts with VYNPC and Hydro-Quebec. We sell our excess power, if any, in the wholesale markets administered by ISO-New England or to third parties primarily in New England. Such sales help to mitigate overall power costs; but price volatility in the wholesale power market can affect results of these mitigation efforts. See Power Supply Matters.

Our retail rates are set by the PSB after considering recommendations of Vermont's consumer advocate, the Vermont Department of Public Service ("DPS"). While our retail rates do not have fuel or power cost adjustment mechanisms, the PSB has previously approved the deferral of extraordinary costs incurred that might normally be expensed by unregulated businesses in order to match these expenses with future revenues. 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. See Retail Rates.

Our current credit rating continues to affect liquidity. We are required to post collateral under performance assurance requirements for certain of our power contracts. At December 31, 2006, we had posted $8.6 million of collateral including issuance of a $4.5 million letter of credit under our $25.0 million revolving credit facility. We have also started to borrow under the credit facility to manage our working-capital requirements, but no amounts were outstanding under this credit facility at December 31, 2006. Although we have taken steps to help ensure adequate liquidity is maintained over the next two years, an unscheduled and prolonged outage of one of our significant power sources, Vermont Yankee or Hydro-Quebec, could have a material detrimental effect on our liquidity without rapid rate relief from our regulators, or supplemental credit facilities. See Liquidity and Capital Resources.

Our primary power supply contracts are with VYNPC and Hydro-Quebec. Combined these contracts make up nearly 80 percent of our committed resources. The contract for power purchases from VYNPC ends in 2012, and deliveries under the contract with Hydro-Quebec end in 2016 with the level of deliveries decreasing starting in 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. Planning for future power supplies with other Vermont utilities and our regulators is a key initiative for us. See Recent Energy Policy Initiatives.

RETAIL RATES

Our retail rates in 2006 were based on a March 29, 2005 PSB Order ("2005 Rate Order") that included, among other things: 1) a 2.75 percent rate reduction beginning April 1, 2005; 2) a $6.5 million pre-tax refund to customers; 3) a 10 percent return on equity (reduced from 11 percent); and 4) a requirement that the gain resulting from the 2004 Connecticut Valley sale be applied to the benefit of ratepayers to compensate for increased costs. The rate order resulted in a $21.8 million pre-tax charge to utility earnings in the first quarter of 2005. In mid-2005, we filed an appeal of portions of the rate order with the Vermont Supreme Court, but the Court issued its decision in mid-2006 rejecting our appeal. The Court's decision had no effect on our financial condition or results of operations for 2006.

On May 15, 2006, we filed a request for PSB approval of a 6.15 percent rate increase (additional revenue of $16.4 million on an annual basis), to be effective February 1, 2007. Later we reached an agreement with the DPS to reduce our rate increase request to 3.73 percent effective January 1, 2007, by reducing our proposed allowed rate of return on common equity from 12 percent to 10.75 percent, which was still higher than the 10 percent allowed in 2006. In November 2006, we reached an agreement with the DPS on our Accounting Order request for recovery of fourth quarter 2005 replacement energy costs associated with a Vermont Yankee scheduled refueling outage. The agreement included recovery of $1.5 million of replacement energy costs over a two-year period and added 0.34 percent to our rate increase request, resulting in a combined rate increase request of 4.07 percent effective January 1, 2007.

On December 7, 2006, the PSB issued an Order ("2006 Rate Order") approving the 4.07 percent rate increase effective January 1, 2007. The 2006 Rate Order provided, among other things, an allowed rate of return on common equity of 10.75 percent capped until our next rate proceeding. The January 1, 2007 rate increase, net of amounts to be returned to customers as described below, will add revenue of approximately $9.9 million annually.

Our Accounting Order request for recovery of the $1.5 million of incremental replacement power costs described above was subject to PSB approval. The 2006 Rate Order requires us to record a regulatory asset or liability for any difference between the replacement power cost amortization included in the 4.07 percent rate increase and the amount approved by the PSB. On January 12, 2007, the PSB issued an Order denying our Accounting Order request. This 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. Instead, we will defer the $1.5 million of revenue over two years and continue such deferral until our next rate proceeding, at which time the total amount deferred will be returned to customers.

Also see Recent Energy Policy Initiatives for a discussion of alternative regulation plans and our proposed rate design.

LIQUIDITY, CAPITAL RESOURCES AND COMMITMENTS

Liquidity At December 31, 2006, we had cash and cash equivalents of $2.8 million included in total working capital of $13.7 million. At December 31, 2005, we had cash and cash equivalents of $6.6 million included in total working capital of $91.5 million. The primary components of cash from operating, investing and financing activities for both periods are discussed in more detail below.

Operating Activities of Continuing Operations: Operating activities provided $26.2 million in 2006. Net income, when adjusted for depreciation, amortization, deferred income tax and other non-cash income and expense items provided $45.5 million. Additionally, special deposits and restricted cash used to meet performance assurance requirements for certain power contracts decreased by $15.5 million because the required amounts were lower and because we issued a $4.5 million letter of credit to meet part of the obligations. We also made $20.8 million in pension trust contributions, $5.2 million in postretirement benefit trust contributions, and $2.4 million in postretirement medical benefit and other benefit-related payments, net of $0.7 million of contributions received from postretirement medical benefit plan participants. Changes in working capital and other items used $6.4 million.

During 2005, operating activities provided $5.3 million. Net income, when adjusted for depreciation, amortization, deferred income tax and other non-cash income and expense items, provided $37.8 million, including a $21.8 million charge, net of $6.5 million of customer refunds, related to the 2005 Rate Order. Additionally, $19.1 million was used to meet performance assurance requirements under power transaction agreements, $4.5 million was contributed to pension and postretirement medical benefit trust funds, $2.5 million was paid for postretirement medical plan out-of-pocket expenses, offset by $0.5 million of contributions received from plan participants and $6.4 million used by working capital and other items.

Investing Activities of Continuing Operations: Investing activities provided $32.1 million in 2006, including $78.0 million in proceeds from net sales and maturities of available-for-sale securities. We sold $50.0 million of available-for-sale securities for the purchase of shares of our common stock through the tender offer that concluded in April 2006 using cash proceeds from the Catamount sale. We used $19.5 million for construction expenditures, $23.3 million for investments in Transco and $4.3 million for the acquisition of utility property. Miscellaneous items contributed $1.2 million.

During 2005, investing activities provided $6.1 million, including $59.25 million of proceeds from the sale of Catamount, less transaction costs of $1.4 million, and $11.0 million from repayment of a note receivable from Catamount. Offsetting these items were $17.6 million for construction expenditures, $38.9 million for net investments in available-for-sale securities, $5.9 million invested in Catamount during the first half of 2005 and $0.4 million for other investing activities. Investments in available-for-sale securities increased primarily because we invested the cash proceeds from the Catamount sale prior to the April 2006 stock buyback. These investments were partially offset by the sale of securities, in part to make collateral payments under the performance assurance requirements described below.

Financing Activities of Continuing Operations: Financing activities used $62.1 million in 2006, including $51.2 million for the tender offer, $10.2 million for dividends paid on common and preferred stock, $2.0 million for preferred stock sinking fund payments, and $1.0 million for capital lease payments. These items were partially offset by $1.3 million from stock issuance proceeds resulting from stock option exercises and $1.0 million from decrease in preferred stock sinking fund payments.

During 2005, financing activities used $14.0 million, including $12.1 million for dividends paid on common and preferred stock, $2.0 million for preferred stock sinking fund payments, and $1.0 million for capital lease payments, partially offset by $1.1 million from stock issuance proceeds.

Discontinued Operations: Discontinued operations are related to Catamount, which was sold in the fourth quarter of 2005. Catamount used $2.5 million during 2005, including a decrease in cash resulting from deconsolidation of Catamount and proceeds received from an October 2005 stock issuance. Operating activities provided $3.8 million, financing activities provided $22.0 million and investing activities used $12.0 million.

Transco: In June 2006, VELCO's Board of Directors, the PSB and the FERC approved a plan to transfer substantially all of VELCO's assets and business operations to Transco. Transco now owns and operates an integrated transmission system in Vermont over which bulk power is delivered to all electric utilities in the state. We invested a total of $23.3 million in Transco in 2006, including $8.9 million on June 30, $0.4 million on July 31 and $14.0 million on September 29. Our investments in Transco will earn an allowed return of 11.5 percent. Based on current projections, Transco expects to need additional capital in the 2007 to 2010 timeframe, but their projections are subject to change based on a number of factors, including revised construction project estimates, timing of regulatory project approvals, and changes in its approved equity to debt ratio. While we have no obligation to invest in Transco's future projects, we will evaluate those investment opportunities on a case-by-case basis and currently intend to make additional investments subject to available liquidity.

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.

Retail Rates: Our retail rates were reduced by 2.75 percent ($7.2 million pre-tax on an annual basis) on April 1, 2005. The rate reduction combined with the 10 percent allowed return on equity (reduced from 11 percent) negatively impacted our cash flow from operations in 2005 and 2006. As described in Retail Rates above, the rate increase effective January 1, 2007 will add approximately $9.9 million to annual retail revenue. We continue to review our costs to serve customers and will request rate increases when warranted. At this time, we are planning to request an additional rate increase in 2007.

Utility Acquisitions: On September 1, 2006, we completed the purchase of substantially all of the plant assets and franchise of Rochester Electric Light and Power Company ("Rochester") for net book value. Rochester was a privately owned electric utility located in Rochester, Vermont. The purchase price of $0.3 million included $0.2 million for net book value of utility plant. The purchase added 900 customers to our customer base.

On December 8, 2006, we completed the purchase of the southern Vermont franchise territory and related plant assets of Vermont Electric Cooperative, a Vermont corporation and electric cooperative, which serves 37,000 customers primarily in central and northern Vermont. The purchase price was approximately $4.3 million and primarily included net utility plant assets at 80 percent of their net book value. The purchase of the southern Vermont service territory added 2,700 customers to our customer base.

While these purchases are not expected to significantly increase earnings, we expect that the consolidation into our existing service territory will provide synergies that enhance service responsiveness and reliability for the combined territories.

Tender Offer: In April 2006, we purchased 2.25 million shares of our common stock through a reverse Dutch auction tender offer that commenced in February 2006. Under the procedures of the tender offer, shareholders could offer to sell some or all of their stock to us at a target price in a range from $20.50 to $22.50 per share. We paid a total of $51.2 million including transactions costs, and the transaction has decreased common shares outstanding by 18.3 percent.

Cash Flow Risks: We believe that cash on hand, cash flow from operations and our $25.0 million credit facility will be sufficient to fund our business. Based on our current cash forecasts, we believe the borrowing capacity under the credit facility will provide sufficient liquidity at least until the end of 2007, and possibly longer. However, an extended 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. 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 described below, primarily as a result of high power market prices.

Financing

Long-Term Debt: Substantially all utility property and plant are subject to liens under the First Mortgage Bonds. Associated scheduled sinking fund payments for the next five years are $0 in 2007, $3.0 million in 2008, $5.5 million in 2009, $0 in 2010 and $20.0 million in 2011. Currently, we are not in default under the terms of any of our debt financing documents.

Credit Facility: We have a three-year $25.0 million unsecured revolving-credit facility with a lending institution pursuant to a Credit Agreement dated October 21, 2005. We expect to make periodic short-term borrowings under the revolving credit facility to manage our working capital requirements. At December 31, 2006, no amounts were outstanding under this facility. On September 26, 2006, a $4.5 million letter of credit was issued under this facility to support certain power-related performance assurance requirements. It expires on September 25, 2008. Currently no amounts have been drawn under the letter of credit.

Letters of Credit: In addition to the letter of credit we issued under the credit facility, 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. These letters of credit are secured under our first mortgage indenture as required by the bank. At December 31, 2006, there were no amounts outstanding under these letters of credit.

Covenants: At December 31, 2006, we were in compliance with all financial and non-financial covenants related to our various debt agreements, letters of credit and credit facility.

Capital Commitments and Contractual Obligations Our business is a capital-intensive because annual construction expenditures are required to maintain the distribution system. Our capital expenditures for the next five years are estimated to be $33.0 million in 2007, $27.5 million in 2008, $22.5 million in 2009, $35.0 million in 2010 and $40.6 million in 2011. These are subject to continuing review and adjustment and actual capital expenditures may vary. Our significant contractual obligations as of December 31, 2006 are summarized in the table below.

	Payments Due by Period (in millions)				
Contractual Obligations	Total	Less than 1 year	1 - 3 years	3 - 5 years	After 5 years
Long-term debt	$116.0	-	$8.5	$20.0	$87.5
Interest on long-term debt (a)	98.5	7.1	14.0	12.8	64.6
Notes payable (b)	13.9	0.4	0.8	0.8	11.9
Redeemable preferred stock	4.0	1.0	2.0	1.0	-
Capital lease	10.3	1.5	2.7	2.4	3.7
Operating leases - vehicle and other (b)	8.1	2.1	3.2	2.2	0.6
Purchased power contracts (c)	1,064.7	144.5	291.8	288.3	340.1
Nuclear decommissioning and other closure costs (d)	14.9	2.7	4.1	3.1	5.0
Total Contractual Obligations	$1,330.4	$159.3	$327.1	$330.6	$513.4

(a) Based on interest rates per sinking fund payment schedule shown in Note 13 - Long-Term Debt and Credit Facility.
(b) Includes interest payments based on interest rates as of December 31, 2006.
(c) 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. See Power Supply Matters for more information.
(d) 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. See Power Supply Matters for more information.

The contractual obligation table above excludes estimated funding for pension and postretirement medical benefit obligations reflected in our consolidated balance sheet. The timing of these payments may vary based on changes in the fair value of plan assets (for pension obligations) and actuarial assumptions. In 2007, we expect to contribute $6.5 million to our pension and postretirement medical trust funds; however, there is no minimum funding requirement for our pension plan. 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 2008 through 2011. Additional obligations related to our nonqualified pension plans are approximately $0.5 million per year.

Capitalization Our capitalization for the past two years follows:

	(in millions)		Percent	
	2006	2005	**2006**	2005
Common stock equity	**$179**	$217	**57%**	61%
Preferred stock*	**12**	14	**4**	4
Long-term debt	**116**	116	**37**	33
Capital lease obligations*	**7**	7	**2**	2
	$314	$354	**100%**	100%

* includes current portion

Credit Ratings On August 1, 2006, Standard and Poor's Ratings Services ("S&P") reaffirmed our BB+ corporate credit rating and our BBB senior secured bond rating. Our preferred stock rating was lowered to B+ from BB-. In their press release, S&P explained that "The lowering of the preferred stock rating reflects Standard and Poor's notching criteria for preferred stock of speculative-grade companies. The criteria requires preferred stock to be rated three notches below the corporate credit rating." In addition, S&P revised our business risk profile score to reflect a less risky rating of "5" from our previous score of "6". S&P ranks utilities on a scale of "1" or "excellent" to "10" or "vulnerable". The revision was in response to the 2005 Catamount sale, the major portion of our unregulated businesses. 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

Performance Assurance At December 31, 2006, we had posted $8.6 million of collateral under performance assurance requirements for certain of our power contracts, including a $4.5 million letter of credit issued under our $25.0 million revolving credit facility.

We are subject to performance assurance requirements associated with our power purchase and sale transactions through ISO-New England under the Financial Assurance Policy for NEPOOL members. At our current credit rating of 'BB+', our credit limit with ISO-New England is zero and we are required to post collateral for all net purchase transactions. ISO-New England reviews collateral requirements on a daily basis. As of December 31, 2006, we had posted $3.5 million of collateral.

We are currently selling power in the wholesale market pursuant to two third-party contracts. One contract extends through mid 2007 and the other through late 2008. We are required to post collateral with these counterparties under certain conditions defined in the contracts. As of December 31, 2006, we had posted $4.5 million in the form of a letter of credit, and $0.5 million in cash.

We are subject to performance assurance requirements associated with power purchase and sale transactions through ISO-New York. Activity in this market has been limited. At December 31, 2006, we had posted $0.1 million of collateral.

We are also subject to performance assurance requirements under our Vermont Yankee power purchase contract (the 2001 Amendatory Agreement). If ENVY, the seller, has commercially reasonable grounds to question our ability to pay for monthly power purchases, ENVY 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, or obtain access to assets through special purpose entities. We have letters of credit that are described in Financing above.

Commitments and Contingencies

Catamount Indemnifications: On December 20, 2005, CRC completed the sale of Catamount to CEC Wind Acquisition, LLC, a Delaware limited liability company established by Diamond Castle Holdings, a New York-based private equity investment firm ("Diamond Castle"). Under the terms of the Catamount sale agreement, we agreed to indemnify Catamount and Diamond Castle, and certain of their respective affiliates, in respect of a breach of certain representations, warranties and covenants, most of which survive until June 30, 2007, except certain items that customarily survive indefinitely. We indemnified the parties against all losses related to taxes for periods prior to the initial closing, subject to a "true up" post-closing. Indemnification is net of insurance and taxes, and materiality is disregarded from all representations and warranties.

Indemnification is subject to a $1.5 million deductible and a $15.0 million cap, excluding certain customary items. Environmental representations are subject to the deductible and the cap, and such environmental representations for two of Catamount's underlying energy projects survive beyond June 30, 2007. Our estimated "maximum potential" amount of future payments related to these indemnifications is limited to $15.0 million.

Power Supply Commitments: We have material power supply commitments for the purchase of power from VYNPC and Hydro-Quebec. These contracts are described in more detail in Power Supply Matters.

OTHER BUSINESS RISKS

In addition to the risks described in Liquidity and Capital Resources above, we are also subject to regulatory risk and wholesale power market risk related to our Vermont electric utility business. These are described in more detail below.

Regulatory Risk: Historically, electric utility rates in Vermont have been based on a utility's costs of service. Electric utilities 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. 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. We are actively participating in planning for and implementing the provisions of these laws. See Recent Energy Initiatives.

Power supply and wholesale power market prices: Our material power supply contracts are principally with Hydro-Quebec and VYNPC. These relatively low-priced 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. As described in Power Supply Matters below, we purchased forced outage insurance to cover additional costs, if any, of obtaining replacement power from other sources if the Vermont Yankee plant experiences unplanned outages during 2007. Average market prices at the times when we purchase replacement energy might be higher than amounts included for recovery in our retail rates. If the amounts are material, we can request regulatory treatment of the costs for recovery from customers in future rates.

Our contract for power purchases from VYNPC ends in 2012, but there is a risk that the plant could be shut down earlier than expected if the plant's owner, Entergy, determines that it is not economical to continue operating the plant. Deliveries under the power contract with Hydro-Quebec end in 2016, but the level of deliveries will be reduced starting in 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.

Market Risk: See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for a discussion of Wholesale Power Market Price Risk.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our discussion and analysis of financial condition, results of operations and cash flows are based upon the accompanying Consolidated Financial Statements, which have been prepared in accordance with GAAP. The preparation of these Consolidated Financial Statements required management to make estimates and judgments that affect the reported amount of assets and liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements. Actual results may differ from these estimates under different assumptions or conditions.

Critical accounting policies and estimates are defined as those that require significant judgment and uncertainties, and potentially may result in materially different outcomes under different assumptions and conditions. Management believes that the accounting policies and estimates that are most critical to reported results of operations, cash flows and financial positions are described below.

Regulatory Accounting We prepare our financial statements in accordance with Statement of Financial Accounting Standards No. 71 ("SFAS No. 71") for our regulated Vermont service territory and FERC-regulated wholesale business. The application of SFAS No. 71 results in differences in the timing and recognition of certain revenues and expenses from those of other businesses and industries. The ratemaking process results in the recording of regulatory assets and other deferred charges based on the probability of current and future cash inflows. They represent incurred or accrued costs that have been deferred because future recovery of these items from customers is probable. The ratemaking process can also result in the recording of regulatory liabilities or deferred credits, which represent amounts collected from customers in retail rates for which the costs have not or are not expected to be incurred.

We continuously review regulatory assets and other deferred charges to assess ultimate recoverability through retail rates. Based on a current evaluation of the factors and conditions expected to influence future cost recovery, we believe future recovery of our regulatory assets in the State of Vermont for our retail and wholesale businesses is probable. In the event that we determine our regulated operations no longer meet the criteria under SFAS No. 71 and there is not a rate mechanism to recover these costs, we would be required to write off $20.5 million of regulatory assets, $12.1 million of other deferred charges and $12.7 million of other deferred credits, for a total extraordinary charge to operations of $19.9 million pre-tax as of December 31, 2006. We would also be required to record pension and postretirement costs of $31.7 million on a pre-tax basis to Accumulated Other Comprehensive Loss as a reduction in stockholder's equity, and would be required to determine any potential impairment to the carrying costs of deregulated plant. Risks associated with recovery of regulatory assets relate to potentially adverse legislation, and judicial or regulatory actions in the future.

Revenues Revenues from the sale of electricity to retail customers are based on PSB-approved rates. Our revenues from retail, resale and other operating activities are generally recorded when service is rendered or when energy is delivered to customers. However, the determination of the energy sales to retail customers is based on monthly meter readings, and estimates are made to accrue unbilled revenue at the end of each accounting period. In order to determine unbilled revenues, we make various estimates including: 1) energy generated, purchased and resold; 2) losses of energy over transmission and distribution lines; 3) kilowatt-hour usage by retail customer mix - residential, commercial and industrial; and 4) average retail customer pricing rates. We use these estimated amounts to calculate the amount of revenue that has been earned or delivered, but not billed, due to the timing of billing cycles used for retail customers. Unbilled revenues totaled $16.7 million at December 31, 2006 and $16.9 million at December 31, 2005.

Pension and Postretirement Medical Benefits We adopted 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") as of December 31, 2006 as required. 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. The adoption of SFAS No. 158 did not impact our Consolidated Statement of Income or Consolidated Statement of Cash Flows, but it did impact our Consolidated Balance Sheet. Upon adoption of SFAS No. 158 we recorded accrued pension and benefit obligations of $31.0 million. Based on historical recovery of pension and other postretirement medical costs through rates we charge our customers, we recognized a regulatory asset of $31.7 million for certain of our pension and postretirement medical costs versus recording a charge to accumulated other comprehensive income. There were other impacts on the Consolidated Balance Sheet as shown in Note 15 - Pension and Postretirement Medical Benefits.

SFAS No. 158 also requires companies with early benefit measurement dates to change their measurement date by 2008 to correspond with their fiscal year-end and to record the financial statement impact as an adjustment to retained earnings. We estimate that changing our annual benefit measurement date from September 30 to December 31 will result in a pre-tax charge to retained earnings of $1.6 million. We are evaluating whether to seek regulatory accounting treatment for this change related to our regulated operations. If regulatory accounting treatment is not received, the total after-tax charge to retained earnings would be approximately $1.0 million.

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 September 30 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 $50.0 million in par value. As of September 30, 2006, the pension discount rate changed from 5.65 percent to 5.95 percent and the postretirement medical discount rate changed from 5.65 percent to 5.80 percent.
- *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. At September 30, 2005, the ROA was 8.25 percent. This rate was used to determine the annual expense for 2006 and will also be used to determine the 2007 expense.
- *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. As of September 30, 2006, the rate of compensation increase changed from 4 percent to 4.25 percent.
- *Health Care Cost Trend* - We project expected increases in the cost of health care. For measurement purposes, we assumed a 10.5 percent annual rate of increase in the per capita cost of covered health care benefits for fiscal 2006, for pre-65 and post-65 claims costs. The rate is assumed to decrease 1 percent in each of the subsequent years until an ultimate trend rate of 5.5 percent is reached.
- *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.

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. Any additional decreases in the discount rate would increase the regulatory asset by the same amount as the projected benefit obligation.

(in thousands)	25 Basis-point Increase in Discount Rate	25 Basis-point Decrease in Discount Rate	25 Basis-point Increase in Expected Return on Assets	25 Basis-point Decrease in Expected Return on Assets
Pension Plan				
Effect on projected benefit obligation as of October 1, 2006	$(1,915)	$2,002	-	-
Effect on 2006 net period benefit cost	$(204)	$203	$(174)	$174
Other Postretirement Medical Benefit Plans				
Effect on accumulated postretirement benefit obligation as of October 1, 2006	$(673)	$705	-	-
Effect on 2006 net periodic benefit cost	$(80)	$81	$(22)	$22

Environmental Liabilities Our regulated electric business is engaged in various operations and activities that subject it 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 environmental remediation, monitoring and other future activities are probable and can be reasonably estimated. At December 31, 2006, we had a reserve of $2.1 million for three sites that are in various stages of remediation. This compares to a reserve of $5.4 million as of December 31, 2005. To our knowledge, there is no pending or threatened litigation regarding any other site with the potential to cause material expense. No government agency has sought funds from us for any other study or remediation.

In 2006 we updated the cost estimates for two of the sites, one located in Rutland, Vermont and the other located in Brattleboro, Vermont. The reserve for the third site is less than $0.1 million. The revised cost estimates for the two sites were finalized in the third quarter of 2006, and we now expect our liability related to remediation efforts at these sites to range from a high of $3.6 million to a low of $1.0 million. Management believes that the most likely cost of the remediation effort for the two sites is $2.1 million, which is $3.2 million less than the accrual at December 31, 2005. The revised cost estimates were based on engineering evaluations of possible remediation scenarios at the sites and Monte Carlo simulations, which are complex mathematical models using a broad range of possible outcomes and statistical information in determining the outcome with the highest likelihood of occurrence. The assumptions used in the Monte Carlo simulations required considerable judgment by Management. The decrease from the previous cost estimate for one of the sites reflects updated information, the availability of advanced remediation technology and our intent to voluntarily clean up the site rather than await a state or federal mandate to complete cleanup. The decrease from the previous cost estimate for the other site reflects the use and specific remediation-related costs for the scenario with the highest likelihood of occurrence. See Note 17 - Commitments and Contingencies for additional information. As with any environmental site, unknown conditions or changes in known conditions that were not reasonably predictable at the time that the cost estimates were revised, could materially affect the estimates and actual site remediation costs.

We reached an agreement with the DPS that a portion of the reduction in estimated remediation costs should be attributed to ratepayers and agreed to request PSB approval of an Accounting Order to defer the ratepayer portion. We plan to submit our request in the near future. As a result, we determined that regulatory treatment for the ratepayer portion was probable and therefore recorded $1.6 million of the $3.2 million reduction in environmental reserves as a deferred credit on the Consolidated Balance Sheet. The remaining $1.6 million was recorded as a reduction in operating costs on the Consolidated Statement of Income.

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. 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 balance sheet, depending on whether the 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.

Our power contracts that are derivatives include: 1) one long-term purchased power contract that allows the seller to repurchase specified amounts of power with advance notice (Hydro-Quebec Sellback #3); 2) one long-term forward sale contract; and 3) one short-term forward purchase contract. We enter into forward sale contracts to reduce price volatility in net power costs, since our long-term power forecasts show energy purchases and production in excess of load requirements. We enter into forward purchase contracts for replacement energy during Vermont Yankee scheduled refueling outages.

The estimated fair values of power contract derivatives are based on over-the-counter quotations or broker quotes at the end of the reporting period, with the exception of Hydro-Quebec Sellback #3 that is valued using a binomial tree model, and quoted market data when available, along with appropriate valuation methodologies. The estimated fair value of power contract derivatives was an unrealized loss of $8.0 million at December 31, 2006 and $17.9 million at December 31, 2005.

Reserve for Loss on Power Contract In accordance with the requirements of SFAS No. 5, *Accounting for Contingencies,* ("SFAS No. 5") in the first quarter of 2004, we recorded a $14.4 million pre-tax loss accrual related to termination of our long-term power contract with Connecticut Valley. The contract was terminated as a condition of the January 1, 2004 sale of Connecticut Valley's plant assets and franchise. The loss accrual represented Management's 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 and the cost of purchased power obligations. The estimated life of the power contracts that were in place to supply power to Connecticut Valley extends through 2015.

The loss accrual was estimated based on assumptions about future power prices, the reallocation of power from the state-appointed purchasing agent ("VEPPI") and future load growth. Management reviews 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.

Income Taxes In accordance with SFAS No. 109, *Accounting for Income Taxes* ("SFAS No. 109"), we recognize tax assets and liabilities for the cumulative effect of all temporary differences between financial statement carrying amounts and the tax basis of assets and liabilities. Investment tax credits associated with utility plant are deferred and amortized ratably to income over the lives of the related properties. A valuation allowance is recorded to reduce the carrying amounts of deferred tax assets if management determines it is more likely than not such tax assets will not be realized.

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 earnings for the past three years included earnings from continuing and discontinued operations as follows (in thousands, except earnings per share):

	2006	2005	2004
Earnings from continuing operations	**$18,101**	$1,410	$7,493
Earnings from discontinued operations	**251**	4,936	16,262
Net Income	**$18,352**	$6,346	$23,755
Earnings per share - basic:			
Earnings from continuing operations	**$1.65**	$0.09	$0.59
Earnings from discontinued operations	**0.02**	0.40	1.34
Earnings per share	**$1.67**	$0.49	$1.93
Diluted:			
Earnings from continuing operations	**$1.64**	$0.08	$0.58
Earnings from discontinued operations	**0.02**	0.40	1.32
Earnings per share	**$1.66**	$0.48	$1.90

The table that follows provides a reconciliation of the primary year-over-year variances in diluted earnings per share for 2006 versus 2005.

2005 earnings per diluted share	**$.48**
Year-over-Year Effects on Earnings:	
Higher resale revenue	.60
Higher equity in earnings from Transco	.10
Decrease in environmental reserves	.09
Higher CRC earnings	.06
Other variances (a)	(.03)
Lower retail sales (a)	(.17)
Higher employee-related costs	(.22)
Discontinued operations	(.38)
Net impact of first-quarter 2005 Rate Order charge	.91
Impact of 2006 stock buyback (b)	.22
2006 Earnings per diluted share	**$1.66**

(a) Excludes 2005 Rate Order charges listed separately.
(b) Reflects the impact of the April 2006 stock buyback which decreased common shares outstanding by about 18 percent.

The table that follows provides a reconciliation of the primary year-over-year variances in diluted earnings per share for 2005 versus 2004.

2004 Earnings per diluted share		**$1.90**
Continuing Operations:		
Higher resale sales	.70	
SFAS No. 5 loss accrual - termination of power contract in 2004	.69	
Vermont utility 11 percent allowed rate of return in 2004	.18	
Higher retail and firm sales (excluding Rate Order refund)	.04	
IRS tax settlement received in 2004	(.09)	
Higher transmission and distribution costs	(.17)	
Higher purchased power costs (excluding Rate Order charge)	(.85)	
Higher other costs (excluding Rate Order charges and SFAS No. 5 loss accrual)	(.09)	
Sub-total		**.41**
Net impact of March 29, 2005 Rate Order recorded in the first quarter of 2005		**(.91)**
Discontinued Operations:		
Gain on December 20, 2005 Catamount sale	.45	
Gain on January 1, 2004 CVEC sale	(1.00)	
Results of discontinued operations	(.37)	
Sub-total		**(.92)**
2005 Earnings per diluted share		**$.48**

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 our operating revenues are generated through retail electric sales. Retail sales revenue is 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 that is excess to 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 for those sales. Operating revenues and related mWh sales are summarized below.

	Revenue (in thousands)			mWh Sales		
	2006	2005	2004	**2006**	2005	2004
Residential	**$124,520**	$127,138	$126,680	**959,455**	978,164	955,261
Commercial	**103,432**	105,363	104,161	**888,537**	902,062	861,916
Industrial	**35,052**	33,873	34,755	**430,348**	414,341	419,090
Other	**1,768**	1,618	1,606	**6,125**	5,535	5,410
Retail sales	**$264,772**	267,992	267,202	**2,284,465**	2,300,102	2,241,677
Resale sales	**53,149**	41,457	26,766	**1,031,171**	662,570	552,885
Retail customer refund	**-**	(6,194)	-	**-**	-	-
Other operating revenues	**7,817**	8,104	8,318	**-**	-	-
Total operating revenues	**$325,738**	$311,359	$302,286	**3,315,636**	2,962,672	2,794,562

The average number of retail customers is summarized below:

	2006	2005	2004
Residential	**131,483**	129,943	128,665
Commercial	**21,506**	21,034	20,551
Industrial	**35**	36	37
Other	**173**	171	171
Total number of retail customers	**153,197**	151,184	149,424

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

	2006 vs. 2005	2005 vs. 2004
Retail sales:		
Volume (mWh)	**$(2,530)**	$7,531
Average price due to customer sales mix	**1,164**	(1,451)
Average price due to rate reduction	**(1,854)**	(5,290)
Subtotal	**(3,220)**	790
Resale sales	**11,692**	14,691
Retail customer refund	**6,194**	(6,194)
Other operating revenues	**(287)**	(214)
Increase in operating revenues	**$14,379**	$9,073

2006 vs. 2005

Operating revenues increased $14.4 million, or 4.6 percent, in 2006 compared to 2005, due to the following factors:

- Retail sales decreased $3.2 million due to lower customer use and a 2.75 percent rate reduction that began in April 2005, partly offset by higher average prices resulting from customer sales mix. Retail customers used less power due to milder winter and summer weather compared to 2005.
- Resale sales increased $11.7 million due to an increased volume of power that was not needed to serve retail customers. The largest increase in available energy for resale resulted from additional Vermont Yankee plant uprate power that we were required to purchase at market rates. We also had more available for resale due to more deliveries under the long-term contract with Hydro-Quebec, increased output from the Vermont Yankee plant (excluding additional uprate power), increased output from our owned and jointly owned generating units, and increased output from Independent Power Producers ("IPP"). As described in Purchased Power below, revenue associated with resale sales was largely offset by the cost of the power that was resold.
- The $6.2 million customer refund in 2005 resulted in a favorable variance when comparing 2006 versus 2005.
- Other operating revenues decreased $0.3 million due to lower transmission revenue, partly offset by third party billings associated with storm restoration performed for other utilities and lower reserves for pole attachments based on the fourth-quarter 2006 settlement of a tariff dispute.

2005 vs. 2004

Operating revenues increased $9.1 million, or 3.0 percent, in 2005 compared to 2004, due to the following factors:

- Retail sales revenue increased $0.8 million resulting from a 2.6 percent increase in sales volume, partially offset by a 2.75 percent rate reduction beginning in April 2005 and lower average unit prices due to customer sales mix. Average residential and commercial customer usage increased primarily due to warmer summer weather in 2005 and a slight increase in the average number of customers, while industrial customer usage decreased slightly.
- Resale sales increased $14.7 million due primarily to more mWh available for resale and higher average rates in 2005 versus the same period in 2004, including the sale of excess replacement power for the fourth-quarter 2005 Vermont Yankee scheduled refueling outage, which was shorter than expected. In 2005, we sold most of our excess power supply through forward sale contracts and the remainder to ISO-New England. In 2004, we sold our excess power supply to ISO-New England and other third parties, but there were fewer mWh available for resale due in large part to an unscheduled Vermont Yankee plant outage in 2004. In total, higher average prices contributed $9.0 million to the favorable variance, increased resale sales volume contributed $5.2 million and higher capacity-related revenues contributed $0.5 million.
- The 2005 Rate Order required a refund to customers for amounts determined by the PSB to be over-collections during the period April 7, 2004 through March 31, 2005. Of the $6.2 million refund, $1.7 million was attributed to 2005 and $4.5 million was attributed to 2004.
- Other operating revenue decreased $0.2 million largely due to higher revenue in 2004 from mutual aid work in Florida and increased reserves in 2005 resulting from negotiations related to a pole attachment tariff settlement. These unfavorable items were partially offset by higher transmission revenue and third-party billings including mutual aid work in Massachusetts and maintenance work for Vermont Yankee plant outages in the third and fourth quarters of 2005.

Purchased Power Our power purchases make up almost 58 percent of total operating expenses. 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		
	2006	2005	2004	**2006**	2005	2004
VYNPC (a)	**$70,592**	$57,266	$58,704	**1,689,390**	1,430,155	1,343,629
Hydro-Quebec	**64,297**	58,377	56,943	**998,365**	832,357	790,017
Independent Power Producers	**23,998**	19,676	20,252	**198,735**	160,396	172,210
Subtotal long-term contracts	**158,887**	135,319	135,899	**2,886,490**	2,422,908	2,305,856
Other purchases	**5,525**	31,296	15,675	**90,440**	264,330	231,182
SFAS No. 5 loss amortizations	**(1,196)**	(1,196)	13,155	**-**	-	-
Maine Yankee, Connecticut Yankee and Yankee Atomic (a)	**5,412**	5,003	2,142	**-**	-	-
2005 Rate Order	**-**	2,441	-	**-**	-	-
Other	**820**	(1,220)	(1,220)	**-**	-	-
Total purchased power	**$169,448**	$171,643	$165,651	**2,976,930**	2,687,238	2,537,038

(a) Purchased power transactions with affiliates. Amounts shown in the table above are shown net of regulatory amortizations and deferrals including our share of VYNPC nuclear insurance settlements that we defer per a PSB Order, and deferral of Yankee Atomic incremental dismantling costs prior to April 1, 2005, when they were eliminated in accordance with the 2005 Rate Order.

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

	2006 vs. 2005	2005 vs. 2004
VYNPC	**$13,326**	$(1,438)
Hydro-Quebec	**5,920**	1,434
Independent Power Producers	**4,322**	(576)
Subtotal long-term contracts	**23,568**	(580)
Other purchases	**(25,771)**	15,621
SFAS No. 5 loss accrual (net of amortizations)	**-**	(14,351)
Nuclear decommissioning costs	**409**	2,861
2005 Rate Order	**(2,441)**	2,441
Other	**2,040**	-
(Decrease) Increase in purchased power	**$(2,195)**	$5,992

2006 vs. 2005

Purchased power expense decreased $2.2 million, or 1 percent, in 2006 compared to 2005 due to the following factors:

- Long-term contract purchases increased $23.6 million resulting from: 1) increased purchases under our long-term contract with VYNPC due to higher plant output including $8.4 million for additional plant uprate power that we were required to purchase at market prices and $4.9 million for higher plant output because the plant operated all year in 2006 but had a three-week refueling outage in the fourth quarter of 2005; 2) more deliveries under the VJO contract with Hydro-Quebec resulting from a change in the capacity factor from 65 percent to 80 percent for the contract year beginning November 1, 2005; and 3) more rainfall in 2006 versus 2005 which increased output from IPPs, the majority of which are hydro facilities.
- Short-term purchases decreased $25.7 million because more power was available from long-term contract sources as described above and our owned sources. While there was no Vermont Yankee plant outage during 2006, we purchased high-cost replacement energy during the fourth quarter 2005 scheduled refueling outage.
- Power costs associated with our ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic increased as a result of updated forecasts of decommissioning and other costs associated with these plants. See discussion of Nuclear Generating Companies below.
- Accounting entries associated with the 2005 Rate Order increased power costs by $2.5 million in 2005 with no comparable charges in 2006.
- Other power costs increased principally due to regulatory amortizations for Millstone Unit #3's scheduled refueling outages versus a net deferral in 2005. Based on approved regulatory accounting treatment, we defer the cost of incremental replacement energy and maintenance costs of scheduled refueling outages, and amortize those costs through the next scheduled refueling outage, which typically spans an 18-month period. Millstone Unit #3's last scheduled refueling outage occurred in October 2005.

2005 vs. 2004

Purchased power expense increased $6.0 million, or 3.6 percent, in 2005 compared to 2004 due to the following factors:

- Long-term purchases decreased $0.6 million related primarily to: 1) lower-priced energy under the power contract with VYNPC, partially offset by more purchases resulting from higher plant output, and 2) lower output from IPPs, offset by 3) more deliveries under our contract with Hydro-Quebec due to a load factor change from 65 percent to 80 percent beginning November 1, 2005. Additionally, deferrals for lower Vermont Yankee output due to uprate-related work were $0.4 million higher than 2004. These deferrals are included in Other in the tables above.
- Short-term purchases increased $15.6 million related primarily to replacement energy purchases for the fourth-quarter 2005 Vermont Yankee plant scheduled refueling outage. The high level of replacement power costs was due in part to high wholesale power market prices driven by the extraordinary effects of hurricanes Katrina and Rita on the price of natural gas. These costs were partially offset by increased resale sales as a result of the shorter-than-anticipated outage. Additionally, replacement energy deferrals for Millstone Unit #3 refueling outages were $0.4 million higher than 2004 and we deferred $0.8 million in 2004 related to a Vermont Yankee plant outage with no comparable deferral in 2005. The net increase of $0.5 million is included in Other in the tables above.
- A $14.4 million loss accrual recorded in the first-quarter of 2004 due to termination of the long-term power contract with Connecticut Valley as described below.

- Nuclear decommissioning costs are comprised of our share of Maine Yankee, Connecticut Yankee and Yankee Atomic decommissioning costs. These costs increased by $2.9 million due to higher Connecticut Yankee rates under FERC-approved tariffs and elimination of accounting deferrals for incremental Yankee Atomic dismantling costs per the Rate Order.
- Accounting entries related to the first-quarter 2005 Rate Order increased purchased power expense by $2.5 million primarily from Yankee Atomic incremental dismantling costs and replacement energy costs from an unscheduled 2004 Vermont Yankee plant outage.

Operating Expenses Operating expenses represent costs incurred to support our core business. Excluding purchased power expense which is described in more detail above, operating expenses increased $3.8 million for 2006 versus 2005 and $7.2 million for 2005 versus 2004. The variances in income statement line items that comprise operating expenses on the Consolidated Statements of Income are shown in the table below.

	2006 over/(under) 2005		2005 over/(under) 2004	
	Total Variance	**Percent**	Total Variance	Percent
Purchased power (explained above)	**$(2,195)**	**(1.3)**	$5,992	3.6
Production	**(844)**	**(8.0)**	935	9.7
Transmission - affiliates	**(1,518)**	**(56.4)**	38	1.4
Transmission - other	**674**	**5.1**	147	1.1
Other operation	**(7,909)**	**(14.0)**	5,353	10.5
Maintenance	**2,014**	**10.1**	3,180	18.9
Depreciation	**123**	**0.8**	330	2.1
Taxes other than income	**446**	**3.2**	277	2.0
Income tax expense (benefit)	**10,833**	*	(3,098)	*
Total operating expenses	**$1,624**	**0.5**	$13,154	4.5

* variance exceeds 100 percent

Production: Production operation costs represent the cost of fuel, operation and maintenance, property insurance, and property tax for our wholly and jointly owned production units. The variances for 2006 versus 2005 and for 2005 versus 2004 were not significant. These generating units produced 11 percent more energy in 2006 than in 2005, primarily due to higher output from our hydro facilities and Millstone Unit #3, both of which are low-cost units to operate. Millstone Unit #3 operated at close to 100 percent capacity in 2006 while it was idle for over a month in 2005 due primarily to a refueling outage in the fourth quarter of 2005. Output from our units in 2005 was 5 percent higher than 2004 primarily due to increased output from our hydro facilities.

Transmission - affiliates: These expenses represent our share of the net cost of service of Transco (previously VELCO) as well as some direct charges for facilities that we rent. We refer to Transco and VELCO as the same entity as VELCO is the operating arm of Transco, which was created in the second quarter of 2006 and now owns the transmission network formerly owned by VELCO. In 2006 transmission expenses from Transco and VELCO decreased $1.5 million from 2005. There was no significant variance for 2005 versus 2004. A more detailed discussion of transmission billings from affiliates follows.

The primary piece of transmission-affiliate expenses is the Vermont Transmission Agreement ("VTA"), which represents Transco's cost of service 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. Transco allocates its monthly cost of service, reduced for NOATT reimbursements and other direct charges, to the Vermont utilities under the VTA. These allocations are based on a formula representing each utility's Vermont load share and other factors, which for us amounts to approximately 42 percent.

In 2006, Transco's cost of service increased significantly ($6 million), due primarily to project additions toward the end of 2005, a significant addition of (pre-tax) equity, and a change in its depreciation methodology. More than offsetting the cost increase was an increase in NOATT reimbursements that Transco received for the cost of its PTF facilities. Starting in July 2006, the NOATT was modified so that collections (and therefore reimbursements) are made not just for facilities placed in service through the prior year, but also for facilities projected to be placed in service in the current year. In large part because Transco expected to place in service a portion of its Northwest Reliability Project in 2006, its NOATT reimbursement increased approximately 50 percent, from $20 million in 2005 to $30 million in 2006. The net impact of the Transco cost increase and NOATT reimbursement increase was a decrease in our VTA cost of $1.5 million. The NOATT modification includes a provision to true-up the estimate of current year costs by comparing the projected annual cost of service to the actual cost of service, with the difference plus interest reflected in the reimbursement rate for the next tariff year.

Transmission - other: These expenses are associated with the cost of purchased transmission service excluding Transmission-affiliates, discussed above, and our transmission operating and maintenance expenses. The bulk of these expenses are our purchase of regional transmission service under the NOATT and charges for the so-called Phase I and II transmission facilities. The variance for 2006 versus 2005 was due to a large increase in the NOATT rate starting in July 2006. There was no significant variance for 2005 versus 2004.

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. Other operation expenses in 2005 included first-quarter 2005 Rate Order charges of $10.7 million that resulted from the revised calculation of overearnings for 2001 - 2003 and the 2004 gain resulting from termination of the power contract with Connecticut Valley. Excluding the effect of 2005 Rate Order charges, other operation expenses increased $2.8 million for 2006 versus 2005 and decreased $5.4 million for 2005 versus 2004. The primary drivers of the year-over-year variances are as follows.

The $2.8 million increase in 2006 resulted primarily from: 1) higher employee-related costs ($4.3 million increase) including pension, active and retiree medical, incentive compensation and the expected medical costs of long-term disability claims; 2) higher fees for professional services ($1.0 million increase) including external audit fees driven by Sarbanes-Oxley compliance and other contractor fees, partially offset by bondholder consent fees in 2005; 3) higher costs for customer accounting ($0.7 million increase) due principally to a customer bankruptcy; partially offset by 4) a third-quarter 2006 reduction in environmental reserves ($1.6 million decrease) based on revised cost estimates and 5) net regulatory amortizations ($1.6 million decrease) beginning in April 2005 per the 2005 Rate Order including deferrals of $0.8 million to match tree trimming and pole treating expenses with amounts currently recovered in rates.

The $5.4 million decrease in 2005 resulted principally from: 1) $3.8 million of deferred earnings in 2004 to achieve an 11 percent return on equity; 2) lower employee-related costs including incentive compensation, medical costs and long-term disability; 3) consulting expenses in 2004 for an IRS tax settlement; partially offset by 4) higher pension costs, and 5) the favorable impact of an environmental insurance settlement in 2004 with no comparable item in 2005.

Maintenance: These expenses are related to costs associated with maintaining our electric distribution system and include costs from our jointly owned generating and transmission facilities. The increase in 2006 from 2005 resulted primarily from higher contractor costs for tree trimming ($1.0 million increase), higher storm restoration costs ($0.4 million increase), and higher other maintenance costs ($0.6 million increase) including stockroom maintenance and minor inventory items. Pursuant to the 2005 Rate Order, beginning April 1, 2005, any differences between actual tree trimming costs and amounts included for recovery in retail rates are being deferred until our next rate proceeding. Therefore, the higher tree-trimming costs in 2006 are partially offset by the favorable impact of regulatory amortizations included in other operation above.

The increase in 2005 from 2004 was related primarily to higher storm restoration costs due to a major storm in October 2005, and higher contractor costs for an annual maintenance outage at McNeil, one of our jointly owned generating units.

Depreciation: We use the straight-line remaining-life method of depreciation. There was no significant variance for 2006 versus 2005 or for 2005 versus 2004.

Taxes other than income: This is related primarily to property taxes and payroll taxes. There was no significant variance for 2006 versus 2005 or for 2005 versus 2004.

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 36.52 percent for 2006, 309.8 percent for 2005 and 21.6 percent for 2004. The effective tax rate increased significantly in 2005 because we had a pre-tax loss of $0.7 million on continuing operations. When the tax benefits of permanent differences and income tax credits are combined with the tax benefit based on the pre-tax loss, the result is an effective tax rate of 309.8 percent

The American Jobs Creation Act of 2004 ("Act") amended Section 45 of the IRS Code to allow a renewable electricity production credit for the production of electricity by certain closed-loop facilities. Our McNeil wood chip plant qualifies for this tax credit, which amounted to $0.2 million in 2006 and 2005. This tax credit, which is based upon the megawatt hours of electricity produced, is expected to be about the same amount for each of the next four years.

On June 7, 2004, the State of Vermont enacted legislation that reduced the state income tax rate from 9.75 percent to 8.9 percent effective January 1, 2006, and from 8.9 percent to 8.5 percent effective January 1, 2007.

See Note 16 - Income Taxes for additional information.

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 $0.8 million in 2006, $0.1 million in 2005 and $0.1 million in 2004. 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.

	2006 over/(under) 2005		2005 over/(under) 2004	
	Total Variance	**Percent**	Total Variance	Percent
Equity in earnings of affiliates	**$1,371**	**73.4**	$644	52.6
Allowance for equity funds during construction	**41**	**51.9**	(70)	(47.0)
Other income	**1,366**	**33.2**	(2,227)	(35.1)
Other deductions	**1,151**	**(32.4)**	(1,590)	81.0
Provision for income taxes	**(1,255)**	*	1,052	(85.3)
Total other income and deductions	**$2,674**	*	$(2,191)	(48.4)

* variance exceeds 100 percent

Equity in earnings of affiliates: These are related to our equity investments including VELCO, Transco and VYNPC. The increase for 2006 versus 2005 resulted primarily from investments that we made in Transco in 2006. The increase in 2005 was related principally to an additional equity investment that we made in VELCO in the fourth quarter of 2004.

Allowance for equity funds during construction: This is the cost of equity financing during construction projects. It is capitalized as part of major utility plant projects when costs applicable to such construction work in progress have not been included in rate base through ratemaking proceedings.

Other income: These items include non-operating rental income principally from rental water heaters, interest and dividend income, interest on temporary investments and miscellaneous other income items. Other income in 2005 included first-quarter 2005 Rate Order charges of $0.8 million for adjustments to carrying charges for certain deferred Vermont Yankee costs. Excluding the effect of 2005 Rate Order charges, other income increased $0.6 million for 2006 versus 2005 and decreased $1.4 million for 2005 versus 2004.

Other income increased in 2006 due primarily to interest income on the Catamount sale proceeds ($0.6 million increase) and the gain on sales of non-utility property ($0.3 million increase), partially offset by lower interest on temporary investments ($0.4 million decrease) resulting from lower cash balances. Other income decreased in 2005 due primarily to regulatory carrying charges in 2004 ($0.4 million decrease) that were eliminated as a result of the 2005 Rate Order, and interest received in 2004 ($1.0 million decrease) related to a favorable IRS tax settlement.

Other Deductions: These items include supplemental retirement benefits and insurance, including changes in the cash surrender value of life insurance policies, non-utility expenses relating to rental water heaters, and miscellaneous other deductions. Other deductions in 2005 included a first-quarter 2005 Rate Order charge of $0.4 million resulting from the disallowance of a portion of Vermont Yankee fuel rod costs. Excluding the effect of the 2005 Rate Order charge, other deductions decreased $0.7 million for 2006 versus 2005 and increased $1.2 million for 2005 versus 2004.

Other deductions decreased in 2006 due primarily to the 2005 impairment and realized losses ($0.6 million increase) associated with certain available-for-sale debt securities that were sold earlier than planned. Other deductions increased in 2005 due to the investment impairment and realized losses, and higher insurance expense ($0.5 million increase) related to death benefits received in 2004.

Benefit (provision) 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.

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

	2006 over/(under) 2005		2005 over/(under) 2004	
	Total Variance	**Percent**	Total Variance	Percent
Interest on long-term debt	**$-**	**0.0**	$(1,454)	(16.8)
Other interest	**(1,249)**	**(53.8)**	1,234	*
Allowance for borrowed funds during construction	**(13)**	**50.0**	31	(54.4)
Total interest expense	**$(1,262)**	**(13.3)**	$(189)	(2.0)

* variance exceeds 100 percent

Interest on long-term debt: There was no significant variance for 2006 versus 2005. The decreases in 2005 from 2004 resulted from lower interest rates in effect following a 2004 bond refinancing. On July 30, 2004, we issued $20 million of 5 percent First Mortgage Bonds, due in 2011, and $55 million of 5.72 percent First Mortgage Bonds, due in 2019. The proceeds were used to repay in full our $75 million Second Mortgage Bonds, at a rate of 8.125 percent that matured on August 1, 2004. The refinancing and lower interest rates have reduced annual interest expense by approximately $2.0 million on a pre-tax basis.

Other interest expense: In 2005 other interest expense included first-quarter 2005 Rate Order charges of $1.2 million related primarily to carrying costs associated with the recalculation of overearnings for 2001 - 2003. Excluding the effect of the 2005 Rate Order charges, there was no significant variance between 2006 and 2005, nor between 2005 and 2004.

Allowance for borrowed funds during construction: This is the cost of debt financing during construction projects that we capitalize as part of the cost of major utility plant projects when costs applicable to such construction work in progress have not been included in rate base through the ratemaking process.

Discontinued Operations
Catamount: A fourth quarter 2006 true-up of federal income taxes related to the 2005 gain on the sale of Catamount resulted in income from discontinued operations of $0.3 million. Catamount's operating expenses shown in the table below include $0.5 million in 2005 and 2004 of costs reallocated to continuing operations. Income from discontinued operations related to Catamount as of December 31 are summarized below (in thousands).

	2006	2005	2004
Operating revenues	**$-**	$-	$-
Operating expenses	**-**	(315)	(315)
Operating Income	**-**	315	315
Other income and (deductions):			
Equity in earnings of non-utility investments	-	1,591	4,220
Gain on sale of non-utility investments	-	-	2,518
Other income	-	2,093	1,895
Other deductions	-	(4,951)	(6,674)
Benefit for income taxes	**251**	856	1,928
Total other income and (deductions)	**251**	(411)	3,887
Total interest expense	**-**	575	280
Net income (loss) from discontinued operations	**251**	(671)	3,922
Gain from disposal, net of $5,183 income tax	**-**	5,607	-
Income from discontinued operations	**$251**	$4,936	$3,922

Connecticut Valley: Components of the January 1, 2004 sale transaction were recorded in both continuing and discontinued operations on the 2004 Consolidated Statement of Income. Income from discontinued operations included a $21.0 million pre-tax, or $12.3 million after-tax, gain on disposal. We also recorded a loss of $14.4 million pre-tax, or $8.4 million after-tax, related to termination of the power contract with Connecticut Valley. The loss was included in purchased power expense. There are no remaining significant business activities related to Connecticut Valley.

POWER SUPPLY MATTERS

Sources of Energy Our power supply portfolio includes a mix of base load, dispatchable and energy-constrained schedulable resources. A breakdown of energy sources is shown below:

	2006	2005	2004
Nuclear - VYNPC	**49%**	46%	46%
Canadian hydro contract	**29**	27	27
Wholly owned hydro and thermal	**7**	7	6
Jointly owned units	**7**	7	7
Independent power producers	**6**	5	6
Other	**2**	8	8
	100%	100%	100%

Power Supply Portfolio Our primary power supply contracts are with VYNPC and Hydro-Quebec. We are also required to purchase power from Independent Power Producers. Our wholly owned units include 20 hydroelectric generating units, two oil-fired gas turbines and one diesel peaking unit with a combined nameplate capability of 74.2 MW. Our jointly owned units include: 1) a 1.73 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 1.78 percent joint-ownership in Wyman #4, a 609 MW oil-fired unit. These sources are used to serve our retail electric load requirements plus any wholesale obligations we enter into.

We manage our power supply portfolio by attempting to optimize the use of those 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 our load obligations each year through 2011, and therefore we enter into fixed-price forward sale transactions to reduce price (revenue) volatility in order to help stabilize our net power costs.

During 2006 we sold power under two separate forward sale contracts that we had entered into in November 2004. One of the sales extends through December 2008. The other ended in December 2006, with the delivery of power contingent on Vermont Yankee plant output. In December 2006 we entered into a forward sale contract for deliveries between 30 and 50 MW from January 1 through June 30, 2007, except during the scheduled Vermont Yankee refueling outage. Delivery under this contract is contingent on Vermont Yankee plant output, eliminating the risks related to sourcing the sale if Vermont Yankee is not operating. We also entered into a transaction with another utility in New England, whereby we effectively swap 10 MW of Vermont Yankee plant output for 10 MW of another nuclear plant's output. We deliver power under this contract only if Vermont Yankee is operating and the other plant is not. Likewise, we receive power under the contract only if the Vermont Yankee plant is not operating but the other nuclear plant is. This swap transaction extends from January 1, 2007 through April 30, 2007.

We also enter into forward purchase contracts for times when the Vermont Yankee plant is not operating. In December 2006, we entered into a contract for the purchase of 100 MW each hour from May 12 to June 6, 2007 for replacement energy during the next Vermont Yankee scheduled refueling outage. Additionally, energy is also sold or bought hourly through the normal ISO-New England settlement process, resulting in a net sale or purchase equal to the imbalance between our resource output and load requirements. On an hourly basis, we net the hourly sales and purchases we make through ISO-New England, and account for those net values as either operating revenues or purchased power expense.

Some of the forward contracts that we enter into meet the definition of a derivative and therefore the fair value of these contracts is recorded on the balance sheet. Due to regulatory accounting, changes in the fair value are not included on our income statements. Also see Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Vermont Yankee We purchase our entitlement share of plant output from VYNPC under a purchased power contract ("PPA") between VYNPC and Entergy Nuclear Vermont Yankee, LLC ("ENVY"). Our entitlement of total plant output was reduced from 35 percent to 29 percent in September 2006 due to the uprate as described below, but our purchase of plant output is similar to the amount we received before the uprate process began. Prices under the PPA range from $39 to $45 per megawatt hour. 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. If market prices rise, however, PPA prices are not adjusted upward in excess of the PPA price. Prior to the change in our entitlement percentage, we purchased a share of uprate power at market rates from mid-March through mid-September based on the terms of the PPA. Purchases of power from VYNPC during 2006, 2005 and 2004 are described in Purchased Power above. Future purchases are expected to be $58.0 million in 2007, $59.0 million in 2008, $64.8 million in 2009, $61.0 million in 2010 and $62.6 million in 2011.

ENVY 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. The plant normally shuts down for about one month every 18 months for maintenance and to insert new fuel into the reactor. The plant's last scheduled refueling outage was in the fourth quarter of 2005. The price that we paid for replacement power during the outage was higher than what was being recovered in retail rates, so we filed a request with the PSB to defer the costs for future recovery in rates. The PSB denied our request in January 2007 but it had no impact on 2006 results since the costs were previously expensed in 2005. The next refueling outage is scheduled to begin in May 2007. As described above we have entered into a forward purchase contract for the purchase of replacement energy during the outage.

On October 3, 2006, we purchased forced outage insurance for $1.3 million, to cover additional costs, if any, of obtaining replacement power from other sources if the Vermont Yankee plant experiences unplanned outages between January 1 and December 31, 2007. The coverage applies to unplanned outages of up to 30 consecutive calendar days per outage event, and provides for payment to us of the difference between hourly spot market prices and the PPA price when the spot price is above the $40/mWh PPA price. Under this coverage, we will receive payments on claims within 30 days of submitting proof of loss. The total maximum coverage is $10.0 million, with a $1.0 million total deductible.

On June 8, 2006, the plant received a new output rating of approximately 620 MW, a 20 percent increase in plant capacity. The uprate required prior approval by the Nuclear Regulatory Commission ("NRC") and PSB. The PSB's March 2004 approval of the Vermont Yankee plant uprate was conditioned on ENVY providing outage protection indemnification ("Ratepayer Protection Proposal" or "RPP") for times the uprate process causes reductions in output that reduce the value of the PPA. Our maximum right to indemnification under the RPP is $2.8 million for the three-year period beginning in May 2004 and ending after completion of the uprate (or a maximum of three years). As of December 31, 2006, we have collected a nominal amount under the RPP. There are three separate issues associated with the uprate and RPP described below.

- On March 16, 2006, a settlement agreement was filed with the PSB resolving all issues that were raised in a petition before the PSB regarding the RPP. Our share of the settlement is estimated to be $1.6 million, including $0.7 million for recovery of incremental replacement power costs associated with a June 2004 outage at the plant. The remainder is for costs incurred between November 4, 2004 and February 28, 2006, when the plant ran at a reduced level due to the uprate project. Pursuant to the 2005 Rate Order, any reimbursement associated with the June 2004 outage shall be recorded as a regulatory liability for return to ratepayers. The settlement is not effective until the PSB issues a final order. We cannot predict the timing or outcome of this matter at this time.
- We are a party to a PSB Docket that was opened in June 2006 because the DPS was seeking additional ratepayer protections in the event that plant output must be reduced due to problems with its steam dryer. On September 18, 2006, the PSB issued an order requiring ENVY to submit a proposal to provide additional ratepayer protections that will protect Vermont utilities and ratepayers if the plant is forced to reduce output because of uprate-related steam dryer problems. The DPS and ENVY reached an agreement in a compliance filing with the PSB, which will provide protections in the event of a derate. The protections will apply to incremental replacement power costs and will remain in effect for at least two months after the refueling outage during which the plant operates successfully with no steam dryer-related outages or derates. The compliance filing is pending approval before the PSB and is not effective until the PSB issues a final order. We cannot predict the outcome of this matter at this time.
- The PPA between ENVY and VYNPC contains a formula for determining the entitlement to power following the uprate. VYNPC and ENVY are seeking to resolve certain differences in the interpretation of the formula. One issue is how much capacity VYNPC and ENVY may bid into the ISO-New England market following the uprate; another issue is the percentage of power that would be delivered under the PPA in the event of a derate. 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 about 50 percent of our committed energy supply and would have to acquire replacement power resources for approximately 40 percent of our estimated power supply needs. Based on projected market prices, the incremental cost of lost power, including capacity, is estimated to average $42.0 million on an annual basis. Based on this estimate, we would require a retail rate increase of 15 percent for full cost recovery. We are not able to predict whether there will be an early shutdown of the Vermont Yankee plant or whether the PSB will 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.

Hydro-Quebec We purchase power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract and related contracts negotiated between us and Hydro-Quebec. The VJO contract runs through 2020, but our purchases under the contract end in 2016. 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, including us, must "step-up" to the defaulting party's share on a pro rata basis. As of December 31, 2006, our obligation is about 47 percent of the total VJO Power Contract through 2016, which represents approximately $606 million, on a nominal basis. The average annual amount of capacity that we will purchase from January 1, 2007 through October 31, 2012 is about 145.3 MW, with lesser amounts purchased through October 31, 2016. Power purchases from Hydro-Quebec during 2006, 2005 and 2004 are described in Purchased Power above.

In 1994, we negotiated a 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 deliveries by 50 MW beginning as early as 2010, 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 load factor of 75 to 50 percent due to adverse hydraulic conditions as measured at certain agreed upon metering stations on regulated and unregulated rivers in Quebec. This second option can be exercised five times through October 2015. Hydro-Quebec has not yet exercised these options.

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 of time. Hydro-Quebec has used all of its elections, resulting in a 65 percent load factor obligation from November 1, 2002 to October 31, 2005. The VJO elected to purchase at an 80 percent load factor for the contract year beginning November 1, 2005, and has made a similar election for the contract year beginning November 1, 2006. The VJO have now used all of their load factor elections. After the contract year ending October 31, 2007, the annual load factor will be at 75 percent for the remainder of the contract, unless all parties agree to change it or there is a reduction due to the hydraulic conditions described above.

Independent Power Producers We purchase power from a number of IPPs that own qualifying facilities under the Public Utility Regulatory Policies Act of 1978. These qualifying facilities produce energy primarily 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. In 2006, power purchases from IPPs amounted to 6.7 percent of total mWh purchased and 19.2 percent of purchased power expense. Purchases during 2006, 2005 and 2004 are described in Purchased Power above. Estimated annual purchases from IPPs are expected to range from $18 million to $20 million for the years 2007 through 2011.

Wholly Owned Generating Units We own and operate 20 hydroelectric generating units, two oil-fired gas turbines and one diesel peaking unit with a combined nameplate capability of 74.2 MW.

In January 2003, we, the Vermont Agency of Natural Resources ("VANR"), Vermont Natural Resources Council and other parties reached an agreement to allow us to relicense the four dams we own and operate on the Lamoille River. The agreement stipulated that subject to various conditions, we begin decommissioning the Peterson Dam, one of the four on the Lamoille River, in 20 years. The agreement required PSB approval of full rate recovery related to decommissioning the Peterson Dam, including recovery of replacement power costs when the dam is out of service. In October 2003, we filed a petition with the PSB for approval of the rate recovery mechanisms, and the case continued to progress through the regulatory process. On December 22, 2006, the PSB issued its Order denying the rate recovery requested in the Petition. Therefore the Company does not intend to decommission the dam.

In June 2005, the FERC issued a 30-year license for the four dams, including Peterson Dam. FERC determined that the VANR waived its rights to issue a water quality certificate. In January 2006, we and the VANR filed timely appeals in federal court. The federal court has stayed all action on the appeals until completion of the proceedings before the PSB and further filings by the parties. The 30-year license remains in effect during such appeals. While the PSB Order has no direct impact on the federal litigation, the issuance of the Order enables parties to make further filings with the federal court. We have subsequently withdrawn our appeal; the appeal by VANR continues to be stayed. We cannot predict the outcome of the litigation at this time.

WHOLESALE MARKET AND TRANSMISSION MATTERS

Locational Installed Capacity Replaced by Forward Capacity Market: In December 2006, ISO-New England implemented a new market mechanism referred to as the Forward Capacity Market ("FCM") for procuring new generation capacity and compensating owners of existing generation capacity. The auction-based FCM prices will commence in June 2010, preceded by a formal transition period that began in December 2006. Starting in 2010 the prices paid for generation capacity will be based on clearing prices resulting from auctions administered by ISO-New England. During the transition period owners of generation will be paid according to a schedule of pre-determined prices starting at $3.05 per kW-month in 2007 and escalating to $4.10 per kW-month through May 2010. The auctions will begin in 2008 and will be designed to procure capacity three or more years ahead of time with a one- to five-year commitment period. FCM includes a mechanism to establish separate zones for capacity when transmission constraints are found to exist. On average, we expect to have committed resources with capacity sufficient to meet our FCM requirements in 2007 and possibly beyond. By 2011 it is expected that we will have to acquire new capacity or purchase it in the FCM.

Regional Transmission Organization: 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. By March 2008, all users will pay the same rate for all facilities.

Under the RTO, Highgate and related facilities, owned by a number of Vermont utilities and Transco (previously VELCO), 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 $1.2 million in 2007, $1.6 million in 2008, and $1.9 million in 2009 and beyond. Our share of the savings was about $0.9 million in 2006 and is included as a reduction of transmission expense.

Vermont Transmission Projects: Transco has completed the construction of several significant upgrades, portions of which were approved by NEPOOL for shared cost treatment in New England-wide rates for transmission services, including the so-called Northwest Reliability Project ("NRP"). The most recent estimated cost of the NRP is about $228 million, including a 15 percent contingency, which represents a $78 million increase from the original estimate that was completed in early 2003.

In addition to the NRP, Transco is 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, Vermont, 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. The condensers are rotating machines similar to motors used to control power flow on electric power transmission systems without burning fuel. The project is expected to cost $10 million and, subject to PSB approval, we plan to begin construction in 2007. The condensers will improve the reliability in the Stratton/ Manchester area of the Southern Loop. VELCO is also working 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 West Dummerston. Non-transmission alternatives including demand side management and generation are being evaluated as a way to solve the reliability issues or defer the need for a transmission line project. We expect to file a petition with the PSB for approval of the transmission improvements in the summer of 2007.

The RTO's regional cost-sharing approach reduces our costs related to qualifying Vermont transmission upgrades, but we are also required to pay a share of the cost for projects occurring elsewhere in New England that support region-wide reliability. The net economic effect on us is expected to be beneficial, as the regional sharing approach provides higher cost and reliability benefits in providing service to our customers. That is because most of the facilities upgrades Transco is constructing improve the reliability and efficiency of the regional transmission network. Therefore, the Vermont transmission projects are mostly funded by regional cost-sharing. Our allocation, based on our percentage of network load, is a small fraction of New England's obligation. Certain future transmission facilities will not qualify for such cost sharing, and those costs will be charged locally (within Vermont) rather than regionally. Our share of such costs will be determined by the classification of each project; therefore, some will be charged directly to specific utilities and some will be shared by all Vermont utilities.

NUCLEAR GENERATING COMPANIES

Millstone Unit #3 We have a 1.7303 joint-ownership percentage in Millstone Unit # 3. As a joint owner, in which Dominion Nuclear Corporation ("DNC") is the lead owner with about 93.4707 percent of the plant joint-ownership, we are responsible for our share of nuclear decommissioning costs. We have an external trust dedicated to funding our joint-ownership share of future decommissioning costs. DNC has suspended contributions to the Millstone Unit #3 Trust Fund because the minimum NRC funding requirements are being met or exceeded. We have also suspended contributions to the Trust Fund, but could choose to renew funding at our own discretion as long as the minimum requirement is met or exceeded. If a need for additional decommissioning funding is necessary, the Company will be obligated to resume contributions to the Trust Fund.

On November 28, 2005, the NRC renewed Millstone Unit #3's operating license, extending the license expiration from November 2025 to November 2045. In May 2006, DNC announced that it is evaluating an undetermined level of power uprate not to exceed 7 percent. A 7 percent uprate would increase our share of plant generation by 1.4 MW, and we would be obligated to pay our ownership share of the related costs. 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 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 is expected to be held in August 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.

Maine Yankee, Connecticut Yankee and Yankee Atomic We own, through equity investments, 2 percent of Maine Yankee, 2 percent of Connecticut Yankee and 3.5 percent of Yankee Atomic. All of these plants have been permanently shut down and have completed or are nearing completion of decommissioning. We are responsible for paying our equity ownership percentage of decommissioning costs and all other costs for these plants. As of December 31, 2006, based on the most recent estimates provided, our share of remaining costs to decommission these three nuclear units is $3.4 million for Maine Yankee, $8.2 million for Connecticut Yankee and $3.3 million for Yankee Atomic. These amounts are recorded as nuclear decommissioning liabilities (current and non-current) on the balance sheet with a corresponding regulatory asset. We adjust associated regulatory assets and nuclear decommissioning liabilities when revised estimates are provided.

All three companies have received approval from FERC for recovery of their estimated costs and we expect any additional increases in these costs to be included in future rate applications with FERC, with any adjustments being charged to their respective sponsors, including us. The FERC-approved settlements for each company are described in more detail below. Historically, our share of these costs has been recovered from retail customers through PSB-approved rates. There is a risk that if in the future FERC disallows recovery of any of these companies' costs in their wholesale rates, the PSB would likely disallow recovery of our share in retail rates.

Department of Energy ("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 DOE was to begin removing spent nuclear fuel from the nuclear plants no later than January 31, 1998 in return for payments by each company into the nuclear waste fund. No fuel has been collected by the DOE, and spent nuclear fuel is being stored at each of the plants. Maine Yankee, Connecticut Yankee and Yankee Atomic collected the funds from wholesale utility customers, including us, under FERC-approved contract rates, and these payments were collected from the our retail customers.

On February 28, 2006, all three companies asked the Court to allow amended damage claim filings. The request was based on a September 2005 decision by the United States Court of Appeals for the Federal Circuit involving another nuclear utility's spent fuel that, among other things, found that plaintiffs in partial breach cases were not entitled to future damages. In the spring of 2006, the trial judge issued a ruling allowing Maine Yankee to seek recovery of damages through December 31, 2002, and Connecticut Yankee and Yankee Atomic to seek recovery of damages through December 31, 2001.

On September 30, 2006, United States Court of Federal Claims Senior Judge Merow issued a favorable ruling for Maine Yankee, Connecticut Yankee and Yankee Atomic in the DOE 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. Most of the reduction in the claimed losses related to disallowed wet pool operating expenses, which the Court felt the companies would have incurred notwithstanding the DOE breach. On December 4, 2006, the DOE filed a notice of appeal in all three cases, and on December 14, 2006, all three companies filed notices of cross appeals. Due to the complexity of the issues and the 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 described below require that damage payments received, net of taxes and net of further spent fuel trust funding, be credited to ratepayers. Our share of these payments, if any, would be credited to our ratepayers as well.

The decision, if upheld, establishes 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 leaves open the question regarding damages in subsequent years, the decision does support future claims for the remaining spent fuel storage installation construction costs. We cannot predict the ultimate outcome of this decision on appeal.

Maine Yankee: On October 3, 2005, Maine Yankee completed its decommissioning efforts and the NRC amended its operating license for operation of the Independent Spent Fuel Storage Installation. Such operation primarily involves ongoing management and maintenance of the on-site spent nuclear fuel storage facility. Beginning November 1, 2004, Maine Yankee's wholesale rates have been based on a September 2004 FERC-approved settlement, which provides for recovery of Maine Yankee's forecasted costs through October 2008 based on a formula rate and replenishment of the DOE Spent Fuel Obligation through collections from November 2008 through October 2010.

Connecticut Yankee: Connecticut Yankee's decommissioning activities are projected to be completed in 2007 followed by transition to Spent Fuel Storage Installation-only activities. Connecticut Yankee had been engaged in litigation with Bechtel Power Corporation ("Bechtel") concerning Connecticut Yankee's July 2003 termination of Bechtel's decommissioning contract for default and related disputes. On March 7, 2006, the parties settled their dispute. Bechtel agreed to pay Connecticut Yankee $15.0 million, release all claims and withdraw its intervention in Connecticut Yankee's FERC Rate Case. Connecticut Yankee agreed to release all claims and that the decommissioning contract be deemed terminated by agreement.

In July 2004, Connecticut Yankee filed with the FERC for recovery of increased costs related to decommissioning of the plant. In its filing Connecticut Yankee sought to increase annual decommissioning collections from $16.7 million to $93.0 million through 2010. In August 2004 the FERC issued an order accepting the new rates, beginning February 1, 2005, subject to the outcome of a hearing and refund to allow for this recovery. In November 2005, the Administrative Law Judge overseeing the hearing issued a ruling favorable to Connecticut Yankee, including findings that the allegations of imprudence raised by interveners were not substantiated. Subsequently, on August 15, 2006, Connecticut Yankee filed a settlement agreement among various interveners that settled all issues in the FERC proceeding. On November 16, 2006, the FERC issued an Order approving the settlement agreement. The notable provisions of the settlement included: 1) reduced decommissioning collections to reflect a lower escalation factor starting 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 the $15.0 million settlement payment from Bechtel; 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) extension of the decommissioning collections from 2010 to December 2015; 6) an investment earnings tracking mechanism for performance greater than or less than certain targets; and 7) resumption of reasonable payments of dividends by Connecticut Yankee to its stockholders subject to certain incentive target balances.

The settlement agreement with Bechtel also required Connecticut Yankee to forego collection of a $10 million regulatory asset. Because the contingency surrounding this regulatory asset existed at June 30, 2006, Connecticut Yankee wrote off the $10 million in the second quarter of 2006, and we recorded our share of the write-off, $0.1 million after-tax, in the second quarter as well. As noted above, successful performance within this incentive may result in a reduction to the initial write-off.

Yankee Atomic: Final site-work on the decommissioning activity concluded in 2006, and NRC approval to begin the Independent Spent Fuel Storage Installation-only operations is expected in 2007. Beginning February 1, 2006, Yankee Atomic's wholesale rates have been based on January 31, 2006 FERC-approved rates subject to refund by Yankee Atomic after hearings and settlement court proceedings. On July 31, 2006, the FERC issued an Order approving a settlement agreement between the parties in the rate case that reduces Yankee Atomic's November 2005 decommissioning cost estimate by $32.0 million and increases the number of years for revenue collection from 2010 to 2014 in order to provide near-term rate relief. Under the approved settlement agreement, Yankee Atomic agreed to reduce its revenue requirements by $79.0 million for the period 2006-2010 and to increase its revenue requirements by $47.0 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.

RECENT ENERGY POLICY INITIATIVES

The State of Vermont continues to examine changes to the provision of electric service absent introduction of retail choice. Several laws have been passed since 2005 that impact electric utilities in Vermont. These include: 1) Act 61 - Renewable Energy, Efficiency, Transmission, and Vermont's Energy Future; 2) Act 208 - Vermont Energy Security and Reliability Act; and 3) Act 123 - Regional Greenhouse Gas Initiative. While provisions of recently passed laws are now being implemented, the 2007 Legislature continues to deliberate new policies designed to reduce electricity consumption, promote renewable energy and reduce greenhouse gas emissions. The major provisions of the new laws that could affect our business are summarized below.

Power Supply Requirements: Act 61 established a program requiring that all Vermont retail electricity providers, in aggregate, supply all of their incremental load growth between January 1, 2005 and January 1, 2012 from new renewable supplies, new Renewable Energy Certificates, or a combination of the two, capped at a total of 10 percent of the statewide kWh sales during calendar year 2005. The program began on January 1, 2007. The PSB will establish utility-specific renewable portfolio standards, if, by July 2013, it determines that the program requirements are not being met. Under this law, we could be required to purchase certain amounts of our energy supply requirement from new renewable sources while maintaining existing renewable power resources. At this time, we are not able to predict how these requirements will impact our business.

Alternative Forms of Regulation: Act 61 allows the DPS and PSB to initiate proceedings to adopt alternative forms of regulation for electric utilities that, besides other criteria, establish a reasonably balanced system of risks and rewards to encourage utilities to operate as efficiently as possible. Rate changes and changes in ratemaking methodologies could be implemented under the terms of an approved alternative regulation plan. The PSB recently approved an alternative regulation plan for Green Mountain Power ("GMP"), Vermont's second-largest electric utility, which covers the years 2007 through 2009. A prominent part of the plan is a power supply adjustment mechanism allowing GMP to adjust rates quarterly to reflect power supply cost changes in excess of a pre-determined amount. There is also a sharing mechanism for earnings in excess of GMP's allowed return on equity and recovery of shortfalls. We are still analyzing GMP's plan. If we conclude that an acceptable alternative regulation plan is feasible, we would file a petition asking the PSB for approval of our plan. Such a filing could occur in 2007.

Rate Design: Act 208 directs the PSB to approve rate designs to encourage the efficient use of natural gas and electricity. One of the provisions of the 2005 Rate Order was that we file a rate design proposal with the PSB. We and the DPS reached an agreement on a proposed rate design and we filed it with the PSB on February 26, 2007. Our proposed rate design contemplates a modest reallocation of revenue by class and greater emphasis on energy charges in reaction to wholesale market energy costs. No party has objected to the proposed rate design plan, and the PSB hearing officer has scheduled hearings in late March. We have requested that the rate design become effective April 1, 2007, or in the alternative, May 1, 2007.

Public Engagement Process: Act 208 directs the DPS and the legislature's Joint Energy Committee to "conduct a comprehensive statewide public engagement process on energy planning, focused on electric energy supply choices facing the state beginning in 2012". The DPS intends to use information gathered from this process to update the 20-Year Electric Plan to provide direction to Vermont utilities and inform the PSB of power supply decisions. We are pursuing two initiatives that are intended to help facilitate the public engagement process. First, we recently completed work on an energy supply decision timeline to help coordinate our integrated resource planning responsibilities with the state's ongoing energy policy deliberations. Second, we have begun an initiative to study the possibility of building new generation in Vermont. Together with other Vermont electric utilities, we expect to engage a consultant to perform an initial feasibility study in the first half of 2007.

RECENT ACCOUNTING PRONOUNCEMENTS

See 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

We consider our most significant market-related risks to be associated with wholesale power markets, equity markets and interest rates. 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 84 and 90 percent of our total energy (mWh) purchases in 2006, 2005 and 2004. The contracts are described in more detail in Item 7, Power Supply Matters and Item 8, Note 17 - Commitments and Contingencies. Summarized information regarding these contracts follows.

		2006		2005		2004	
	Expires	**mWh**	**$/mWh**	mWh	$/mWh	mWh	$/mWh
Hydro-Quebec (a)	2016	**998,365**	**$64.40**	832,357	$70.16	790,017	$72.08
VYNPC (b)	2012	**1,689,390**	**$41.78**	1,430,155	$40.05	1,343,629	$43.69

(a) Under the terms of the Hydro-Quebec contract, there is a defined energy rate that escalates at general inflation 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 our general surplus, we enter into forward sale transactions from time to time to reduce price volatility of our forecasted 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 the case when power from Vermont Yankee is not available as expected, we are typically 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 typically in a sale position. In that case, increased wholesale power market prices should decrease our net power costs.

We account for some of our power contracts as derivatives under the guidance of SFAS No. 133. These derivatives are described in more detail in Item 7, Critical Accounting Policies and Estimates and Power Supply Matters. At December 31, 2006, we had three power contract derivatives with a total estimated fair value of an unrealized loss of $8.0 million. Summarized information related to the fair value of these derivatives is shown in the table below (in thousands):

	Forward Sale Contract	Forward Purchase Contract	Hydro-Quebec Sellback #3
Fair value at January 1, 2006 - unrealized loss	$(12,935)	$-	$(4,977)
Change in fair value, including amounts settled	8,973	(304)	1,246
Fair value at December 31, 2006 - unrealized loss	$(3,962)	$(304)	$(3,731)
Source	Over-the-counter-quotations	Over-the-counter-quotations	Quoted market data & valuation methodologies
Estimated fair value for changes in projected market price:			
10 percent increase	$(5,677)	$71	$(6,341)
10 percent decrease	$(2,247)	$(679)	$(1,437)

Per a PSB-approved Accounting Order, changes in fair value of derivatives are recorded as deferred charges or deferred credits on the Consolidated Balance Sheets depending on whether the 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 due to 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 Item 7, Critical Accounting Policies and Estimates, and 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, 2006, the trust held debt securities of $1.4 million.

As of December 31, 2006, 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 locks or swap agreements in place.

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

	Expected Maturity Date						
	2007	2008	2009	2010	2011	Thereafter	Total
Fixed Rate ($)	**$6.9**	$6.9	$6.7	$6.7	$6.1	$64.5	$97.8
Average Fixed Interest Rate (%)	**6.22%**	6.22%	6.22%	6.22%	6.36%	7.03%	
Variable Rate ($)	**$0.6**	$0.6	$0.6	$0.4	$0.4	$1.1	$3.7
Average Variable Rate (%)	**3.69%**	3.69%	3.68%	3.65%	3.65%	3.64%	

Equity Market Risk: As of December 31, 2006, our pension trust held marketable equity securities in the amount of $58.6 million and our Millstone Unit #3 decommissioning trust held marketable equity securities of $4.0 million. We also maintain a variety of insurance policies in a Rabbi Trust with a current value of $7.1 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.

Index to 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, 2006 and 2005, 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, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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 provide a reasonable basis for our opinion.

In our opinion, 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1, the Company adopted Statement on Financial Accounting Standard No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans*, as of December 31, 2006.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, 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 13, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Hartford, Connecticut
March 13, 2007

CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except share data)

	For the Years Ended		
	2006	2005	2004
Operating Revenues	**$325,738**	$311,359	$302,286
Operating Expenses			
Purchased Power - affiliates	**75,527**	61,140	62,345
Purchased Power - other sources	**93,921**	110,503	103,306
Production	**9,728**	10,572	9,637
Transmission - affiliates	**1,174**	2,692	2,654
Transmission - other	**13,919**	13,245	13,098
Other operation	**48,682**	56,591	51,238
Maintenance	**22,039**	20,025	16,845
Depreciation	**16,498**	16,375	16,045
Taxes other than income	**14,358**	13,912	13,635
Income tax expense (benefit)	**8,569**	(2,264)	834
Total Operating Expenses	**304,415**	302,791	289,637
Operating Income	**21,323**	8,568	12,649
Other Income			
Equity in earnings of affiliates	**3,240**	1,869	1,225
Allowance for equity funds during construction	**120**	79	149
Other income	**5,487**	4,121	6,348
Other deductions	**(2,401)**	(3,552)	(1,962)
Provision for income taxes	**(1,437)**	(182)	(1,234)
Total Other Income	**5,009**	2,335	4,526
Interest Expense			
Interest on long-term debt	**7,196**	7,196	8,650
Other interest	**1,074**	2,323	1,089
Allowance for borrowed funds during construction	**(39)**	(26)	(57)
Total Interest Expense	**8,231**	9,493	9,682
Income from continuing operations	**18,101**	1,410	7,493
Income from discontinued operations, net of income tax (includes gain on disposal of $5,607 in 2005 and $12,354 in 2004)	**251**	4,936	16,262
Net Income	**18,352**	6,346	23,755
Dividends declared on preferred stock	**368**	368	368
Earnings available for common stock	**$17,984**	$5,978	$23,387
Per Common Share Data:			
Basic earnings from continuing operations	**$1.65**	$0.09	$0.59
Basic earnings from discontinued operations	**0.02**	0.40	1.34
Basic earnings per share	**$1.67**	$0.49	$1.93
Diluted earnings from continuing operations	**$1.64**	$0.08	$0.58
Diluted earnings from discontinued operations	**0.02**	0.40	1.32
Diluted earnings per share	**$1.66**	$0.48	$1.90
Average shares of common stock outstanding - basic	**10,756,027**	12,258,508	12,118,048
Average shares of common stock outstanding - diluted	**10,827,182**	12,366,315	12,301,187
Dividends declared per share of common stock	**$0.69**	$1.15	$0.92

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

	For the Years Ended		
	2006	2005	2004
Net Income	**$18,352**	$6,346	$23,755
Other comprehensive income, net of tax:			
Investments:			
Unrealized holding gain (loss)			
net of income taxes of $60 in 2006, $(43) in 2005 and $(155) in 2004	**89**	(64)	(228)
Realized (gain) loss			
net of income taxes of $(45) in 2006, $215 in 2005 and $0 in 2004	**(69)**	316	-
Minimum pension liability adjustment			
net of income taxes of $203 in 2006, $(50) in 2005 and $40 in 2004	**285**	(74)	58
Foreign currency			
Other comprehensive loss from discontinued operations			
net of income taxes of $0 in 2006, $(178) in 2005 and $(178) in 2004	**-**	(462)	(445)
	305	(284)	(615)
Comprehensive Income	**$18,657**	$6,062	$23,140

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	For the Years Ended December 31, 2006	2005	2004
Cash flows provided (used) by:			
OPERATING ACTIVITIES			
Net income	**$18,352**	$6,346	$23,755
Deduct: Income from discontinued operations, net of income taxes	**(251)**	(4,936)	(16,262)
Income from continuing operations	**18,101**	1,410	7,493
Adjustments to reconcile net income to net cash provided by operating activities:			
Equity in earnings of affiliates	**(3,240)**	(1,869)	(1,225)
Dividends received from affiliates	**2,106**	1,938	1,229
Depreciation	**16,498**	16,375	16,045
Amortization of capital leases	**1,096**	1,020	1,021
Deferred income taxes and investment tax credits	**3,820**	(1,835)	(3,596)
Regulatory and other amortization, net	**(3,354)**	(3,113)	(3,001)
Non-cash employee benefit plan costs	**9,997**	7,973	7,266
Environmental reserve adjustment	**(1,609)**	-	-
Share-based compensation	**899**	108	300
Charge related to Rate Order (net of $6.5 million customer refund)	-	15,312	-
Reserve for loss on power contract (SFAS No. 5 loss accrual)	-	-	14,351
Vermont Utility 11% allowed rate of return adjustment	-	-	3,823
Other non-cash expense and (income), net	**1,123**	500	(830)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable and unbilled revenues	**(5,456)**	590	(1,411)
Decrease in accounts payable	**(252)**	(1,798)	(145)
Increase in accounts payable - affiliates	**620**	638	7
(Increase) decrease in other current assets	**(761)**	793	1,161
Decrease (increase) in special deposits and restricted cash for power collateral	**15,512**	(19,094)	-
Employee benefit plan funding	**(28,420)**	(6,980)	(4,196)
Decrease in accrued income taxes and other current liabilities	**(893)**	(6,380)	(11,692)
(Increase) decrease in other long-term assets	**(169)**	127	(715)
Increase (decrease) in other long-term liabilities and other	**551**	(446)	(917)
Net cash provided by operating activities of continuing operations	**26,169**	5,269	24,968
INVESTING ACTIVITIES			
Construction and plant expenditures	**(19,504)**	(17,558)	(20,174)
Investments in available-for-sale securities	**(256,431)**	(277,812)	(317,899)
Proceeds from sale of available-for-sale securities	**334,390**	238,906	315,245
Investment in affiliates (Transco and Velco)	**(23,291)**	-	(7,008)
Acquisition of utility property (Rochester Electric and Vermont Electric Coop)	**(4,306)**	-	-
Investment in discontinued operations	-	(5,900)	-
Note receivable repayment from (advanced to) discontinued operations	-	11,000	(11,000)
Proceeds from sales of discontinued operations, net of transaction costs	-	57,914	30,164
Decrease (increase) in restricted cash	**883**	(883)	-
Return of capital from investments in affiliates and other	**359**	435	227
Net cash provided by (used for) investing activities of continuing operations	**32,100**	6,102	(10,445)
FINANCING ACTIVITIES			
Proceeds from issuance of common stock	**1,267**	1,163	2,593
Proceeds from issuance of long-term debt	-	-	75,000
Retirement of long-term debt	-	-	(75,000)
Treasury stock acquisition - tender offer	**(51,186)**	-	-
Retirement of preferred stock subject to mandatory redemption	**(2,000)**	(2,000)	(2,000)
Net change in special deposits held for preferred stock redemptions	**1,000**	-	-
Common and preferred dividends paid	**(10,164)**	(12,140)	(12,174)
Proceeds from borrowings under revolving credit facility	**18,100**	13,400	-
Repayments under revolving credit facility	**(18,100)**	(13,400)	-
Reduction in capital lease obligations and other	**(963)**	(1,045)	(1,463)
Net cash used for financing activities of continuing operations	**(62,046)**	(14,022)	(13,044)
DISCONTINUED OPERATIONS			
Decrease in cash resulting from deconsolidation of Catamount	-	(16,373)	-
Net cash provided by operating activities	-	3,830	4,187
Net cash used for investing activities	-	(11,972)	(13,312)
Net cash provided by financing activities	-	22,020	8,340
Effect of exchange rate changes on cash	-	-	(19)
Net cash used for discontinued operations	-	(2,495)	(804)
Net (decrease) increase in cash and cash equivalents	**(3,777)**	(5,146)	675
Cash and cash equivalents at beginning of the period	**6,576**	11,722*	11,047*
Cash and cash equivalents at end of the period	**$2,799**	$6,576	$11,722*

*At the end of the periods, Assets of discontinued operations included cash of $2.5 million in 2004 and $3.3 million in 2003.

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

CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	December 31	
	2006	2005
ASSETS		
Utility plant		
Utility plant, at original cost	**$517,816**	$506,496
Less accumulated depreciation	**226,018**	222,167
Utility plant, at original cost, net of accumulated depreciation	**291,798**	284,329
Property under capital leases	**7,485**	7,094
Construction work-in-progress	**8,496**	8,588
Nuclear fuel, net	**1,017**	1,222
Total utility plant, net	**308,796**	301,233
Investments and other assets		
Investments in affiliates	**39,339**	15,801
Non-utility property, less accumulated depreciation ($4,048 in 2006 and $4,063 in 2005)	**1,640**	2,033
Millstone decommissioning trust fund	**5,476**	4,885
Available-for-sale securities	**-**	5,450
Other	**7,120**	6,411
Total investments and other assets	**53,575**	34,580
Current assets		
Cash and cash equivalents	**2,799**	6,576
Available-for-sale securities	**-**	72,432
Restricted cash	**3,081**	883
Special deposits	**1,500**	21,094
Accounts receivable, less allowance for uncollectible accounts ($1,707 in 2006 and $2,614 in 2005)	**27,042**	22,682
Accounts receivable - affiliates, less allowance for uncollectible accounts ($48 in 2006 and $48 in 2005)	**73**	71
Unbilled revenues	**16,654**	16,900
Materials and supplies, at average cost	**5,298**	4,339
Prepayments	**7,389**	8,048
Deferred income taxes	**2,899**	3,199
Assets held for sale	**386**	-
Other current assets	**1,446**	859
Total current assets	**68,567**	157,083
Deferred charges and other assets		
Regulatory assets	**52,179**	30,444
Other deferred charges - regulatory	**12,127**	21,045
Other deferred charges and other assets	**5,694**	7,048
Total deferred charges and other assets	**70,000**	58,537
TOTAL ASSETS	**$500,938**	$551,433

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

CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	December 31 2006	2005
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common stock, $6 par value, 19,000,000 shares authorized, 12,382,801 issued and 10,132,826 outstanding at December 31, 2006 and 12,283,405 issued and outstanding at December 31, 2005	**$74,297**	$73,695
Other paid-in capital	**54,225**	52,513
Accumulated other comprehensive loss	**(544)**	(414)
Deferred compensation - employee stock ownership plans	**-**	(5)
Treasury stock, at cost (2,249,975 shares)	**(51,186)**	-
Retained earnings	**102,560**	91,581
Total common stock equity	**179,352**	217,370
Preferred and preference stock not subject to mandatory redemption	**8,054**	8,054
Preferred stock subject to mandatory redemption	**3,000**	4,000
Long-term debt	**115,950**	115,950
Capital lease obligations	**6,612**	6,153
Total capitalization	**312,968**	351,527
Current liabilities		
Current portion of preferred stock subject to mandatory redemption	**1,000**	2,000
Accounts payable	**6,382**	7,066
Accounts payable - affiliates	**12,022**	11,402
Notes payable	**10,800**	10,800
Accrued income taxes	**578**	769
Dividends declared	**-**	2,825
Nuclear decommissioning costs	**2,737**	5,677
Power contract derivatives	**1,554**	4,498
Other current liabilities	**19,758**	20,592
Total current liabilities	**54,831**	65,629
Deferred credits and other liabilities		
Deferred income taxes	**32,467**	28,647
Deferred investment tax credits	**3,720**	4,099
Nuclear decommissioning costs	**12,166**	14,670
Asset retirement obligations	**3,041**	4,059
Accrued pension and benefit obligations	**37,547**	25,436
Power contract derivatives	**6,443**	13,414
Other deferred credits - regulatory	**12,687**	15,424
Other deferred credits and other liabilities	**25,068**	28,528
Total deferred credits and other liabilities	**133,139**	134,277
Commitments and contingencies		
TOTAL CAPITALIZATION AND LIABILITIES	**$500,938**	$551,433

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

CONSOLIDATED STATEMENT OF CHANGES IN COMMON STOCK EQUITY

(in thousands, except share data)

	Common Stock					Treasury Stock			
	Shares Issued	Amount	Other Paid-in Capital	Accumulated Other Comprehensive Income(loss)	Deferred Compensation	Share	Amount	Retained Earnings	Total
Balance, December 31, 2003	12,020,738	$72,119	$51,334	$485	$(969)	-	$-	$87,472	$210,441
Net Income								23,755	23,755
Other comprehensive loss				(615)					(615)
Common stock issuance:									
Stock compensation plans	76,979	462	1,102					(15)	1,549
Dividend reinvestment plan	90,863	545	1,367						1,912
Allocation of benefits - performance and restricted plans			(1,927)		728				(1,199)
Amortization of benefits performance plans					165				165
Amortization of benefits restricted plans	4,513	27	68		40				135
Dividends declared:									
Common - $0.92 per share								(11,142)	(11,142)
Cumulative non-redeemable preferred stock								(368)	(368)
Amortization of preferred stock issuance expenses			20						20
Balance, December 31, 2004	12,193,093	$73,153	$51,964	$(130)	$(36)	-	$-	$99,702	$224,653
Net Income								6,346	6,346
Other comprehensive loss				(284)					(284)
Common stock issuance:									
Stock compensation plans	37,320	224	606						830
Dividend reinvestment plan	41,822	251	660						911
Allocation of benefits - performance and restricted plans			(752)						(752)
Amortization of benefits performance plans			(123)						(123)
Amortization of benefits restricted plans	11,170	67	133		31				231
Dividends declared:									
Common - $1.15 per share								(14,099)	(14,099)
Cumulative non-redeemable preferred stock								(368)	(368)
Amortization of preferred stock issuance expenses			25						25
Balance, December 31, 2005	12,283,405	$73,695	$52,513	$(414)	$(5)	-	$-	$91,581	$217,370
Net income								18,352	18,352
Other comprehensive income				305					305
Adjustment to initially apply SFAS No. 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			473		5				478
Dividends declared:									
Common - $0.69 per share								(6,971)	(6,971)
Cumulative 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

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

Description of Business Central Vermont Public Service Corporation (the "Company") is a Vermont-based electric utility that transmits, distributes and sells electricity. The Company's 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. In 2005 CRC completed the sale of Catamount Energy Corporation ("Catamount"), its wholly owned subsidiary that invested in wind energy projects in the United States and the United Kingdom. Other wholly owned subsidiaries of the Company include: Custom Investment Corporation ("Custom"), a passive investment subsidiary that holds the Company's investment in Vermont Yankee Nuclear Power Corporation ("VYNPC"); CV Realty, Inc., a real estate company whose purpose is to own, acquire, buy, sell and lease real and personal property and interests; Central Vermont Public Service Corporation - East Barnet Hydroelectric, Inc., which was created for the purpose of financing and constructing a hydroelectric facility in Vermont, which became operational September 1, 1984 and has been leased and operated by the Company since its in-service date; and Connecticut Valley Electric Company ("Connecticut Valley"), which completed the sale of substantially all of its plant assets and franchise on January 1, 2004.

Catamount and Connecticut Valley are presented as discontinued operations in the accompanying consolidated financial statements in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* ("SFAS No. 144"). See Note 5 - Discontinued Operations.

Basis of Consolidation The accompanying consolidated financial statements include the accounts of the Company and its subsidiaries in which it has a controlling interest. Inter-company transactions have been eliminated in consolidation. Jointly owned generating and transmission facilities are accounted for on a proportionate consolidated basis using the Company's ownership interest in each facility. The Company's 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 the Company does not maintain a controlling financial interest are accounted for using the equity method when the Company has the ability to exercise significant influence over their operations. Under this method, the Company records its ownership share of the net income or loss of each investment in its consolidated financial statements. The Company has 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 Note 4 - Investments in Affiliates.

Use of Estimates The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP") requires management 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 Management's 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 The Company is 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. The Company prepares its financial statements in accordance with SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71"), for its regulated Vermont service territory and FERC-regulated wholesale business. The application of SFAS No. 71 results in differences in the timing of recognition of certain expenses from those of other businesses and industries. In order for the Company to report its results under SFAS No. 71, its rates must be designed to recover its costs of providing service, and the Company 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 the Company's regulated operations. In the event the Company determines that it no longer meets the criteria for applying SFAS No. 71, the accounting impact would be an extraordinary non-cash charge to operations of an amount that would be material unless stranded cost recovery is allowed through a rate mechanism. Criteria that could give rise to the discontinuance of SFAS No. 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.

Based on a current evaluation of the factors and conditions expected to impact future cost recovery, Management believes future recovery of its regulatory assets in the State of Vermont for its retail and wholesale businesses is probable. In the event that the Company 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, result in an extraordinary charge to operations of $19.9 million pre-tax at December 31, 2006. See Note 8 - Retail Rates and Regulatory Accounting for additional information.

Financial Statement Presentation The focus of the Company's 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. The Company's operating revenues and expenses (including related income taxes) are those items that ordinarily are included in the determination of its 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 nonutility operating results, expenses of a type 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 its allowed rate of return on equity rather than as a direct cost of service revenue requirement.

The focus of the Company's 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.

Unregulated Business Eversant's primary business activity is the rental of water heaters 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.

Discontinued Operations The Company's discontinued operations include Catamount and Connecticut Valley. The Company began to present Catamount's results as discontinued operations in the fourth quarter of 2005 based on its decision to sell all of its interest in Catamount, and consummation of the sale on December 20, 2005. The Company began to present Connecticut Valley's results as discontinued operations in the second quarter of 2003 based on the New Hampshire Public Utility Commission's ("NHPUC") approval of the sale of Connecticut Valley's plant assets and franchise to Public Service Company of New Hampshire ("PSNH"). The sale to PSNH was completed on January 1, 2004. Certain corporate costs previously allocated to Catamount in 2005 and 2004 that were not eliminated by the sale were reallocated back to continuing operations. See Note 5 - Discontinued Operations.

Subsidiary Stock Transactions SEC Staff Accounting Bulletin ("SAB") 51, *Accounting for Sales of Stock by a Subsidiary*, requires that the difference between the carrying amount of the parent's investment in a subsidiary and the underlying net book value of the subsidiary after the issuance of stock by the subsidiary be reflected as a gain in the statement of income or as an equity transaction. The Company has elected to record gains on the sale of stock by a subsidiary to the statement of income and initially adopted this policy in 2005. See Note 5 - Discontinued Operations.

Income Taxes In accordance with SFAS No. 109, *Accounting for Income Taxes* ("SFAS No. 109"), the Company recognizes 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. The Company records a valuation allowance for deferred tax assets if management determines that it is more likely than not that such tax assets will not be realized. See Note 16 - Income Taxes.

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. The Company records contractual or firm wholesale sales in the month that power is delivered. The Company also engages 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, the Company aggregates these hourly sales and hourly purchases and reports them as operating revenue and operating expenses, respectively.

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

Reserve for Loss on Power Contract In accordance with the requirements of SFAS No. 5, *Accounting for Contingencies ("SFAS No. 5")*, the Company recorded a $14.4 million pre-tax loss accrual in the first quarter of 2004 related to termination of its long-term power contract with Connecticut Valley. The contract was terminated as a condition of the Connecticut Valley sale. The loss accrual represented management's 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 and the net cost of purchased power obligations. The estimated life of the Company's power contracts that were in place to supply power to Connecticut Valley extends through 2015. The $14.4 million loss accrual is included in Purchased Power on the 2004 Consolidated Statement of Income. The loss accrual is being amortized on a straight-line basis through 2015.

Valuation of Long-Lived Assets The Company periodically evaluates the carrying value of long-lived assets, including its investments in nuclear generating companies, its unregulated investments, and its 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 on long-lived assets have been recorded as of December 31, 2006 and 2005.

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 (in thousands):

	2006	2005
Wholly owned electric plant in service	**$404,414**	$393,528
Jointly owned generation and transmission units	**110,496**	110,401
Completed construction	**2,863**	2,524
Held for future use	**43**	43
Utility plant, at original cost	**517,816**	$506,496
Accumulated depreciation	**(226,018)**	(222,167)
Property under capital leases, net	**7,485**	7,094
Construction work-in-progress	**8,496**	8,588
Nuclear fuel, net	**1,017**	1,222
Total Utility Plant, net	**$308,796**	$301,233

Property Under Capital Leases The Company records its commitments with respect to the Hydro-Quebec Phase I and II transmission facilities, and other equipment, as capital leases. At December 31, 2006 Property under Capital Leases was comprised of $24.2 million of original cost less $16.7 million of accumulated amortization. At December 31, 2005, original cost was $22.5 million and accumulated amortization was $15.4 million. See Note 17 - Commitments and Contingencies.

Depreciation The Company uses the straight-line remaining life method of depreciation. The total composite depreciation rate was 3.19 percent of the cost of depreciable utility plant in 2006, 3.18 percent in 2005 and 3.23 percent in 2004.

Allowance for Funds During Construction Allowance for funds 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. AFUDC rates used by the Company were 8.4 percent in 2006, 8.4 percent in 2005 and 9.5 percent in 2004. 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 (in thousands):

	2006	2005
Asset retirement obligations at January 1	**$4,059**	$3,643
Revisions in estimated cash flows	**(1,184)**	(202)
Accretion	**178**	108
Liabilities settled during the period	**(12)**	-
FIN 47 asset retirement obligations recognized in transition	**-**	510
Asset retirement obligations at December 31	**$3,041**	$4,059

The Company has legal retirement obligations for decommissioning related to its joint-owned nuclear plant, Millstone Unit #3, and has an external trust fund dedicated to funding its share of future costs. The year-end aggregate fair value of the trust fund was $5.5 million in 2006 and $4.9 million in 2005, and is included in Investments and Other Assets on the Consolidated Balance Sheets. The revisions in estimated cash flows shown in the table above are related to a new cash flow study in 2006 and changes in Millstone Unit #3 license renewal probability from 85 percent to 100 percent in 2005.

The Company adopted FIN 47, *Accounting for Conditional Asset Retirement Obligations* ("FIN 47"), at December 31, 2005, as required. FIN 47 clarified the scope and timing of liability recognition for conditional asset retirement obligations. Upon adoption of FIN 47, the Company recorded an asset retirement obligation of $0.5 million, and established a regulatory asset to recognize future recoveries of the recorded asset retirement obligation through depreciation rates.

The Company considers its 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. The Company has not recorded an asset retirement obligation associated with asbestos abatement at certain of its sites because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated.

Non-legal Removal Costs: The Company's 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 $8.5 million in 2006 and $7.6 million in 2005 are included in Other Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

Environmental Liabilities The Company is engaged in various operations and activities that subject it to inspection and supervision by both federal and state regulatory authorities including the United States Environmental Protection Agency. The Company's 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 Note 17 - Commitments and Contingencies.

Derivative Financial Instruments The Company accounts for certain 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.

The Company's power contracts that are derivatives include: 1) one long-term purchased power contract that allows the seller to repurchase specified amounts of power with advance notice (Hydro-Quebec Sellback #3); 2) one long-term forward sale contract; and 3) one short-term forward purchase contract. The Company enters into forward sale contracts to reduce price volatility, since its long-term power forecasts show energy purchases and production in excess of load requirements. The Company enters into forward purchase contracts for replacement energy during Vermont Yankee scheduled refueling outages.

Based on a PSB-approved Accounting Order, the Company records the change in fair value of power contract derivatives as deferred charges or deferred credits on the balance sheet, depending on whether the 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. See Note 6 - Financial Instruments.

Share-Based Compensation The Company adopted SFAS No. 123R, *Share-Based Payment* ("SFAS No. 123R"), on January 1, 2006, as required. SFAS No. 123R replaced SFAS No. 123, *Accounting for Stock-Based Compensation*, and superseded APB Opinion No. 25, *Accounting for Stock Issued to Employees.* The Company elected the modified prospective method, therefore prior periods have not been revised for comparative purposes. Under SFAS No. 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, which is the vesting period. The Company had previously accounted for share-based compensation costs under APB No. 25 and related guidance. Accordingly, no compensation expense was recognized for stock options granted in periods prior to January 1, 2006 because they were granted at the market value of the underlying shares on the date of grant. Adoption of SFAS No. 123R did not have a material effect on the Company's financial position or results of operations. See Note 9 - Share-Based Compensation.

The table below illustrates the effect on net income and earnings per share as if the fair value method had been applied to all stock-based compensation in years prior to adoption of SFAS No. 123R (in thousands, except per share amounts).

	2005	2004
Earnings available for common stock, as reported	$5,978	$23,387
Add: Share-based compensation expense included in reported net income, net of tax	62	176
Deduct: Share-based compensation expense under fair value method, net of tax	(192)	(420)
Pro forma net income	$5,848	$23,143
Earnings per share:		
Basic - as reported	$0.49	$1.93
Basic - pro forma	$0.48	$1.91
Diluted - as reported	$0.48	$1.90
Diluted - pro forma	$0.47	$1.88

Pension and Benefits The Company's 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.* The Company uses the fair value method to value all asset classes included in its pension and postretirement medical benefit trust funds.

The Company adopted the recognition and disclosure provisions of SFAS No. 158 as of December 31, 2006, as required. The recognition provisions of SFAS No. 158 primarily resulted in the Company increasing accrued pension and benefit obligations by $31.0 million and regulatory assets by $30.7 million. There was no impact to the Consolidated Statement of Income or the Consolidated Statement of Cash Flows. See Note 15 - Pension and Postretirement Medical Benefits for more information. Also see Recent Accounting Pronouncements below.

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

	2005	**2006** (before the adoption of SFAS No. 158)	**2006** (after the adoption of SFAS No. 158)
Pension and benefits:			
Minimum pension liability adjustments	$(394)	**$(109)**	-
Amount included in Accumulated other comprehensive loss after the adoption of SFAS No. 158	-	-	**$(544)**
Loss on investments	(20)	-	-
Accumulated other comprehensive loss	$(414)	**$(109)**	**$(544)**

Cash and Cash Equivalents The Company considers all liquid investments with an original maturity of three months or less when acquired to be cash and cash equivalents.

Restricted Cash Restricted cash in 2006 includes the funds held by ISO-New England for performance assurance requirements described in Note 17 - Commitments and Contingencies. Restricted cash in 2005 included funds held for property release requirements under the first mortgage indenture.

Special Deposits Special deposits include collateral payments made by the Company under performance assurance requirements for certain of its power contracts as described in Note 17 - Commitments and Contingencies. It also includes mandatory sinking fund payments of $1 million in 2006 and 2005, and an optional sinking fund payment of $1 million in 2005, for the Company's preferred stock subject to mandatory redemption.

Reclassifications The Company has reclassified certain line items within Operating Activities, Investing Activities and Financing Activities on the 2005 and 2004 Consolidated Statements of Cash Flows to separately report and conform to the 2006 presentation. These reclassifications did not change any of the category totals previously reported.

The Company has reclassified Property under capital leases included in Utility plant, at original cost on the 2005 Consolidated Balance Sheet to separately report and conform to the 2006 presentation. This reclassification decreased the sub-total Utility plant, at original cost, net of accumulated depreciation by $7. 1 million but did not change Total Utility Plant, net or Total Assets on the 2005 Consolidated Balance Sheet.

Supplemental Financial Statement Data Supplemental financial information for the accompanying financial statements is provided below. All amounts are shown in thousands.

Other Income: The components of other income on the Consolidated Statements of Income for the years ended December 31 follow:

	2006	2005	2004
Interest on temporary investments	**$1,603**	$1,311	$1,436
Non-utility revenue and non-operating rental income	**1,878**	1,932	1,997
Amortization of contributions in aid of construction - tax adder	**888**	843	829
Other interest and dividends	**511**	584	212
Regulatory asset carrying costs	-	(653)	864
Interest income - IRS audit refunds	-	-	970
Gain on sale of non-utility property	**317**	12	-
Miscellaneous other income	**290**	92	40
Total	**$5,487**	$4,121	$6,348

Other Deductions: The components of other deductions on the Consolidated Statements of Income for the years ended December 31 follow:

	2006	2005	2004
Supplemental retirement benefits and insurance	**$568**	$709	$247
Non-utility expenses	**1,281**	1,226	1,174
Realized losses on available-for-sale securities	**151**	573	95
Vermont Yankee fuel rod disallowance - 2005 Rate Order	**-**	403	-
Miscellaneous other deductions	**401**	641	446
Total	**$2,401**	$3,552	$1,962

Other Current Liabilities: The components of other current liabilities on the Consolidated Balance Sheets at December 31 follow:

	2006	2005
Deferred compensation plans and other	**$2,889**	$2,569
Accrued employee-related costs	**4,136**	3,253
Other taxes and Energy Efficiency Utility	**3,169**	3,016
Cash concentration account - outstanding checks	**1,332**	3,021
Obligation under capital leases	**873**	941
Miscellaneous accruals	**7,359**	7,792
Total	**$19,758**	$20,592

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

	2006	2005
Environmental Reserve	**$1,752**	$5,016
Non-legal removal costs	**8,474**	7,627
Contribution in aid of construction - tax adder	**5,229**	4,881
Reserve for loss on power contract	**9,567**	10,763
Other	**46**	241
Total	**$25,068**	$28,528

Allowance for Uncollectible Accounts: At December 31, 2005, the allowance for uncollectible accounts included a $1.4 million reserve related to a billing dispute and tariff settlement. This reserve was reversed in 2006 reflecting a refund of certain disputed amounts based on final settlement of the tariff.

Assets Held for Sale: In the third quarter of 2006, the Company determined that one of its properties located in Middlebury, Vermont meets the criteria for classification as held for sale. The Company is actively pursuing potential buyers of the property, which previously housed one of its service centers. This asset is classified as held for sale on the Consolidated Balance Sheet in accordance with SFAS No. 144.

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 2006, the Company declared cash dividends of 69 cents per share of common stock, and paid cash dividends of 92 cents per share. In 2005, the Company declared cash dividends of $1.15 per share and paid cash dividends of 92 cents per share of common stock. In 2004, the Company declared 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:

	2006	2005	2004
Interest (net of amounts capitalized)	**$8,109**	$8,886	$10,973
Income taxes (net of refunds)	**$6,300**	$6,086	$15,078

Construction and plant expenditures on the Consolidated Statements of Cash Flows reflect actual payments made during the periods. The Company accrues for construction and plant-related expenditures at the end of each reporting period. At December 31, 2006, $0.5 million of construction and plant-related accruals were included in Accounts Payable, and less than $0.4 million were included in Other Current Liabilities. At December 31, 2005, $1.0 million of construction and plant-related accruals were included in Accounts Payable and $0.5 million were included in Other Current Liabilities.

The Company maintains a cash concentration account for payments related to its routine business activities. At the end of each reporting period, the Company records the book overdraft amount resulting from outstanding checks as a current liability. Changes in the book overdraft position are reflected in operating activities on the Consolidated Statements of Cash Flows.

Recent Accounting Pronouncements

FIN 48: 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. FIN 48 is effective for the Company as of January 1, 2007 and is required to be implemented prospectively as a change in accounting principle with a cumulative effect adjustment recorded as an adjustment to the opening retained earnings balance. The Company is currently evaluating the potential impact that FIN 48 will have on its consolidated financial statements and cannot reasonably estimate the impact at this time.

SAB 108: In September 2006, the SEC issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* ("SAB 108"). SAB 108 provides interpretive guidance on how effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. SAB 108 establishes an approach whereby the effects of all unrecorded identified errors should be considered on both the balance sheet and income statement rather than on only one of the statements. The provisions of SAB 108 are effective for annual financial statements covering the first fiscal year ending after November 15, 2006. The initial application of SAB 108 did not impact the Company's financial position, results of operations or cash flows.

EITF 06-04: In September 2006, the FASB issued EITF Issue 06-04, *Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split Dollar Life Insurance Arrangements,* ("EITF 06-04"). EITF 06-04 requires employers to record a liability for future benefits for endorsement split-dollar life insurance arrangements that provide a postretirement benefit to an employee. The guidance in this EITF becomes effective fiscal periods beginning after December 15, 2007 (beginning January 1, 2008 for the Company). The Company is currently evaluating the impact, if any, EITF 06-04 will have on its financial position, results of operations and cash flows.

SFAS No. 157: In September 2006, the FASB issued FASB Statement No. 157, *Fair Value Measurements* ("SFAS No. 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 GAAP. As a result of SFAS No. 157, there is now a common definition of fair value to be used throughout GAAP. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 (beginning January 1, 2008 for the Company). The Company has not yet evaluated the impact that SFAS No. 157 will have on its financial position, results of operations and cash flows.

SFAS No. 158: As described above, the Company adopted the recognition and disclosure provisions of SFAS No. 158 as of December 31, 2006. SFAS No. 158 also requires companies to measure plan assets and benefit obligations as of the same date as their fiscal year-end balance sheet date. This provision of SFAS No. 158 is effective for the Company in December 2008. The Company estimates that changing its annual benefit measurement date from September 30 to December 31 will result in a pre-tax charge to retained earnings of $1.6 million. The Company is evaluating whether it will seek rate recovery of $1.4 million related to its regulated operations. If rate recovery is permitted, a regulatory asset would be recorded for $1.4 million. If rate recovery is not permitted, the total after-tax charge to retained earnings would be approximately $1.0 million.

SFAS No. 159: In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities* ("SFAS No. 159"). SFAS No. 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. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007 (beginning January 1, 2008 for the Company). The Company has not yet evaluated what impact, if any, the adoption of SFAS No. 159 will have on its financial position, results of operations and cash flows.

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 (in thousands, except share information):

	2006	2005	2004
Numerator for basic and diluted EPS:			
Income from continuing operations	**$18,101**	$1,410	$7,493
Dividends declared on preferred stock	**368**	368	368
Net income from continuing operations available for common stock	**$17,733**	$1,042	$7,125
Denominators for basic and diluted EPS:			
Weighted-average basic shares of common stock outstanding	**10,756,027**	12,258,508	12,118,048
Dilutive effect of stock options	**66,971**	106,119	143,646
Dilutive effect of performance shares	**4,184**	1,688	39,493
Weighted-average diluted shares of common stock outstanding	**10,827,182**	12,366,315	12,301,187

In the second quarter of 2006, the Company purchased 2,249,975 shares of its common stock as described in Note 10 - Treasury Stock. Outstanding stock options totaling 60,077 in 2006 and 192,764 in 2005 were excluded from the computation of diluted shares because the exercise prices were above the average market price of the common shares. All outstanding stock options were included in the computation of diluted shares in 2004 because the exercise prices were lower than the average market price of the common shares.

NOTE 3 - ACQUISITIONS
Rochester Electric On September 1, 2006, the Company completed the purchase of substantially all of the plant assets and the franchise of Rochester Electric Light and Power Company ("Rochester") for $0.3 million. Rochester was a privately owned electric utility located in Rochester, Vermont. The PSB approved the transaction on August 22, 2006 including the Company's request to defer certain incremental transaction costs for recovery in retail rates. The purchase price included $0.2 million for the net book value of Rochester's retail electric and distribution system and facilities. These are included in Utility plant, at original cost ($0.9 million) and Accumulated depreciation ($0.7 million) on the Consolidated Balance Sheet.

Vermont Electric Cooperative On December 8, 2006, the Company completed the purchase of the assets and franchise of Vermont Electric Cooperative's ("VEC") southern Vermont service territory for $4.4 million. VEC is a Vermont corporation and electric cooperative, which serves about 37,000 customers, most of whom are located in central and northern Vermont. The PSB approved the transaction on December 4, 2006 including the Company's request to defer certain incremental transaction costs for recovery in retail rates.

The purchase price included $4.1 million for the utility plant assets, which was about 80 percent of their net book value. The Company recorded an acquisition adjustment of $1.0 million as a component of utility plant, representing the difference between the purchase price and net book value. These amounts are included in Utility plant, at original cost ($7.0 million) and Accumulated depreciation ($1.9 million) on the Consolidated Balance Sheet. The PSB's approval of the transaction allows the Company to amortize the acquisition adjustment over the estimated remaining life of the assets acquired.

NOTE 4 - INVESTMENTS IN AFFILIATES

The Company's equity method investments at December 31 follow (in thousands):

	Ownership	**2006**	2005
Vermont Electric Power Company, Inc.:			
Common stock	47.05%	**$11,247**	$11,260
Preferred stock	48.03%	**188**	202
Subtotal		**11,435**	11,462
Vermont Transco LLC (a)	29.86%	**24,430**	-
Vermont Yankee Nuclear Power Corporation	58.85%	**2,825**	2,802
Connecticut Yankee Atomic Power Company	2.00%	**276**	936
Maine Yankee Atomic Power Company	2.00%	**332**	565
Yankee Atomic Electric Company	3.50%	**41**	36
Total Investments in Affiliates		**$39,339**	$15,801

(a) Vermont Transco LLC was formed by Vermont Electric Power Company, Inc. and its owners in the second quarter of 2006.

Vermont Electric Power Company, Inc. ("VELCO") and Vermont Transco LLC ("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. In June 2006, VELCO's Board of Directors, the PSB and the FERC approved a plan to transfer substantially all of VELCO's business operations to Transco, a Vermont limited liability company formed by VELCO and its owners, including the Company. On June 30, 2006, VELCO's assets were transferred 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 VELCO, Transco, the Company, 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 the Company, Green Mountain Power, VELCO and Transco.

The Company invested a total of $23.3 million in Transco in 2006, including $8.9 on June 30, $0.4 million on July 31 and $14.0 million on September 29. The third quarter investments increased the Company's initial interest in Transco from 20.1 percent to 30.28 percent. During the fourth quarter of 2006, the Company's ownership in Transco changed to 29.86 percent as a result of Transco receiving additional capital investments from other Vermont utilities. The Company's ownership interest in Transco is represented by Class A Units that have an allowed rate of return of 11.5 percent. As of December 31, 2006, the Company's total direct and indirect interest in Transco was 44.34 percent.

During 2006, the Company assessed its ownership interest in Transco under the provisions of FIN 46R and concluded that Transco is not a variable interest entity. The Company also reassessed its ownership interest in VELCO and continues to conclude that it is not a variable interest entity.

Equity in earnings from VELCO amounted to $1.3 million in 2006, $1.4 million in 2005 and $0.8 million in 2004. These amounts are included in Equity in earnings of affiliates on the Company's Consolidated Statements of Income. Cash dividends received amounted to $1.4 million in 2006 and $1.5 million in 2005, including $0.1 million for return of capital from VELCO's Class C preferred stock in both years. VELCO's revenues shown in the table below include sales to the Company of $2.7 million in 2006, 2005 and 2004. These amounts are included in Transmission - affiliates on the Company's Consolidated Statements of Income. Accounts payable to VELCO amounted to $5.4 million at December 31, 2006 and $5.9 million at December 31, 2005.

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

	2006	2005	2004
Operating revenues	**$35,808**	$31,119	$28,295
Operating income	**$11,578**	$8,165	$7,008
Net income before non-controlling interest	**$6,112**	$3,018	$1,683
Less members non-controlling interest in net income	**3,245**	-	-
Net income	**$2,867**	$3,018	$1,683

	2006	2005
Current assets	**$31,847**	$26,115
Non-current assets	**279,322**	161,613
Total assets	**311,169**	187,728
Less:		
Current liabilities	**96,598**	93,392
Non-current liabilities	**133,727**	69,930
Members non-controlling interest	**56,469**	-
Net assets	**$24,375**	$24,406

Transco's unaudited summarized financial information (included above in Velco's summarized consolidated financial information) from inception at June 30 to December 31 follows (in thousands).

	2006
Operating revenues	**$18,330**
Operating income	**$7,950**
Net income	**$5,527**

	2006
Current assets	**$18,890**
Non-current assets	**274,793**
Total assets	**$293,683**
Less:	
Current liabilities	**$82,213**
Non-current liabilities	**129,843**
Net assets	**$81,627**

Equity in earnings from Transco amounted to $1.5 million in 2006, and is included in Equity in earnings of affiliates on the Company's Consolidated Statement of Income. Transco's billings to the Company primarily include Transco's cost of service under the Vermont Transmission Agreement and the Company's share of charges and reimbursements under the NEPOOL Open Access Transmission Tariff ("NOATT"). At December 31, 2006 the Company's share of charges under the Vermont Transmission Agreement and NOATT reimbursements resulted in a net credit of $1.5 million which is included as a reduction in Transmission - affiliates on the Company's Consolidated Statement of Income, and also reflected as a reduction of the same amount in Transco's operating revenues shown in the table above. The NOATT reimbursements primarily resulted from a modification in the tariff beginning July 1, 2006 that now provides reimbursements for projects expected to be placed in service during the tariff year. Accounts payable to Transco amounted to $0.8 million at December 31, 2006. Cash distributions received amounted to $0.4 million in 2006.

Vermont Yankee Nuclear Power Corporation ("VYNPC") VYNPC sold its nuclear plant to Entergy Nuclear Vermont Yankee, LLC ("ENVY") in July 2002. The sale agreement included a purchased power contract ("PPA") between VYNPC and ENVY. Under the PPA, VYNPC pays ENVY for generation at fixed rates, and in turn, bills the PPA charges from ENVY with certain residual costs of service through a FERC tariff to the Company and the other VYNPC sponsors. The Company's entitlement to energy produced by the Vermont Yankee plant is about 29 percent. See Note 17 - Commitments and Contingencies.

Although the Company owns 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 the Company's ability to exercise control over VYNPC. The Company assessed its ownership interest in VYNPC under the provisions of FIN 46R and concluded that VYNPC is not a variable interest entity.

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

	2006	2005	2004
Operating revenues	**$201,325**	$160,613	$167,399
Operating income (loss)	**$3,513**	$(321)	$87
Net income	**$748**	$660	$538

	2006	2005
Current assets	**$28,460**	$26,767
Non-current assets	**129,461**	126,365
Total assets	**157,921**	153,132
Less:		
Current liabilities	**15,569**	16,790
Non-current liabilities	**137,551**	131,581
Net assets	**$4,801**	$4,761

Equity in earnings from VYNPC amounted to $0.4 million in 2006, $0.4 million in 2005 and $0.3 million in 2004. These amounts are included in Equity in earnings from affiliates on the Company's Consolidated Statements of Income. VYNPC's revenues shown in the table above include sales to the Company of $70.1 million in 2006, $55.7 million in 2005 and $58.3 million in 2004. These amounts are included in Purchased power - affiliates on the Company's Consolidated Statements of Income. Accounts payable to VYNPC amounted to $5.5 million at December 31, 2006 and $5.4 million at December 31, 2005. Cash dividends received amounted to $0.4 million in 2006 and $0.4 million in 2005.

Maine Yankee, Connecticut Yankee and Yankee Atomic The Company is responsible for paying its ownership percentage of decommissioning and all other costs for Maine Yankee, Connecticut Yankee and Yankee Atomic. All of the plants have been permanently shut down and have completed or are nearing completion of decommissioning. All three companies collect decommissioning and closure costs through FERC-approved wholesale rates charged under power purchase agreements with several New England utilities, including the Company. Historically, the Company's share of these costs has been recovered from its retail customers through PSB-approved rates, including the Company's current retail rates. Management believes, based on historical rate recovery, its share of decommissioning and closure costs for each plant will continue to be recovered through the regulatory process. However, there is a risk that if in the future FERC disallows recovery of any of these companies' costs in their wholesale rates, the PSB would likely disallow recovery of the Company's share in its retail rates.

Information related to 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	$136.0	$170.4	$3.4
Connecticut Yankee	$184.7	$410.3	$8.2
Yankee Atomic	$117.1	$93.9	$3.3

The remaining obligations are the estimated remaining decommissioning costs in 2006 dollars for the period 2007 through 2023 for Maine Yankee and Connecticut Yankee and through 2022 for Yankee Atomic. Revenue requirements are the estimated future payments to recover estimated decommissioning and all other costs for 2007 and forward, in nominal dollars. Revenue requirements include Maine Yankee and Connecticut Yankee collections for required contributions to pre-1983 spent fuel funds, but not Yankee Atomic because it has already collected and paid these required pre-1983 contributions. The Company's share of revenue requirements shown in the table above is based on its ownership percentage in each plant. These amounts are included in regulatory assets and nuclear decommissioning liabilities (current and non-current) on the Company's Consolidated Balance Sheets.

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 DOE was to begin removing spent nuclear fuel from the nuclear plants no later than January 31, 1998 in return for payments by each company into the nuclear waste fund. No fuel has been collected by the DOE, and spent nuclear fuel is being stored at each of the plants. Maine Yankee, Connecticut Yankee and Yankee Atomic collected the funds from wholesale utility customers, including the Company, under FERC-approved contract rates, and these payments were collected from the Company's retail customers.

On February 28, 2006, all three companies asked the Court to allow amended damage claim filings. The request was based on a September 2005 decision by the United States Court of Appeals for the Federal Circuit involving another nuclear utility's spent fuel that, among other things, found that plaintiffs in partial breach cases were not entitled to future damages. In the spring of 2006, the trial judge issued a ruling allowing Maine Yankee to seek recovery of damages through December 31, 2002, and Connecticut Yankee and Yankee Atomic to seek recovery of damages through December 31, 2001.

On September 30, 2006, United States Court of Federal Claims Senior Judge Merow issued a favorable ruling for Maine Yankee, Connecticut Yankee and Yankee Atomic in the DOE 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. Most of the reduction in the claimed losses related to disallowed wet pool operating expenses, which the Court felt the companies would have incurred notwithstanding the DOE breach. On December 4, 2006, the DOE filed a notice of appeal in all three cases, and on December 14, 2006, all three companies filed notices of cross appeals. Due to the complexity of the issues and the 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 described below require that damage payments, net of taxes and net of further spent fuel trust funding, be credited to ratepayers including the Company. The Company's share of these payments, if any, would be credited to its ratepayers as well.

The decision, if upheld, establishes 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 leaves open the question regarding damages in subsequent years, the decision does support future claims for the remaining spent fuel storage installation construction costs. The Company cannot predict the ultimate outcome of this decision on appeal.

Maine Yankee: The Company's share of decommissioning and other costs amounted to $1.3 million in 2006, $1.2 million in 2005 and $1.3 million in 2004. These are included in Purchased power - affiliates on the Company's Consolidated Statements of Income.

On October 3, 2005, Maine Yankee completed its decommissioning efforts and the Nuclear Regulatory Commission ("NRC") amended its operating license for operation of the Independent Spent Fuel Storage Installation. Such operation primarily involves ongoing management and maintenance of the on-site spent nuclear fuel storage facility. Beginning November 1, 2004, Maine Yankee's wholesale rates have been based on a September 2004 FERC-approved settlement, which provides for recovery of Maine Yankee's forecasted costs through October 2008 based on a formula rate and replenishment of the DOE Spent Fuel Obligation through collections from November 2008 through October 2010.

Connecticut Yankee: The Company received $0.6 million from common stock redemption in December 2006. The Company's share of decommissioning and other costs amounted to $2.4 million in 2006, $2.4 million in 2005 and $0.9 million in 2004. These are included in Purchased power - affiliates on the Company's Consolidated Statements of Income. Connecticut Yankee's decommissioning activities are projected to be completed in 2007 followed by a transition to Spent Fuel Storage Installation-only activities.

In July 2004, Connecticut Yankee filed with the FERC for recovery of increased costs related to decommissioning of the plant. In its filing Connecticut Yankee sought to increase annual decommissioning collections from $16.7 million to $93.0 million through 2010. In August 2004 the FERC issued an order accepting the new rates, beginning February 1, 2005, subject to the outcome of a hearing and refund to allow for this recovery. In November 2005, the Administrative Law Judge overseeing the hearing issued a ruling favorable to Connecticut Yankee, including findings that the allegations of imprudence raised by interveners were not substantiated. Subsequently, on August 15, 2006, Connecticut Yankee filed a settlement agreement among various interveners that settled all issues in the FERC proceeding. On November 16, 2006, the FERC issued an Order approving the settlement agreement. The notable provisions of the settlement included: 1) reduced decommissioning collections to reflect a lower escalation factor starting 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 the $15.0 million settlement payment from Bechtel; 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) extension of the decommissioning collections from 2010 to December 2015; 6) an investment earnings tracking mechanism for performance greater than or less than certain targets; and 7) resumption of reasonable payments of dividends by Connecticut Yankee to its stockholders subject to certain incentive target balances.

Connecticut Yankee had been engaged in litigation with Bechtel Power Corporation ("Bechtel") concerning Connecticut Yankee's July 2003 termination of Bechtel's decommissioning contract for default and related disputes. On March 7, 2006, the parties settled their dispute. Bechtel agreed to pay Connecticut Yankee $15.0 million, release all claims and withdraw its intervention in Connecticut Yankee's FERC Rate Case. Connecticut Yankee agreed to release all claims and to deem the decommissioning contract terminated by agreement. The settlement agreement also required Connecticut Yankee to forego collection of a $10 million regulatory asset. Because the contingency surrounding this regulatory asset existed at June 30, 2006, Connecticut Yankee wrote off the $10 million in the second quarter of 2006, and the Company recorded its share of the write-off, $0.1 million after-tax, in the second quarter as well. As noted above, successful performance within this incentive may result in a reduction to the initial write-off.

Yankee Atomic: The Company's share of decommissioning and other costs amounted to $1.7 million in 2006, $1.9 million in 2005 and $1.9 million in 2004. These are included in Purchased power - affiliates on the Company's Consolidated Statements of Income.

Final site-work on the decommissioning activity concluded in 2006, and NRC approval to begin the Independent Spent Fuel Storage Installation-only operations is expected in 2007. Beginning February 1, 2006, Yankee Atomic's wholesale rates have been based on January 31, 2006 FERC-approved rates subject to refund by Yankee Atomic after hearings and settlement court proceedings. On July 31, 2006, the FERC issued an Order approving a settlement agreement between the parties in the rate case that reduces Yankee Atomic's November 2005 decommissioning cost estimate by $32.0 million and increases the number of years for revenue collection from 2010 to 2014 in order to provide near-term rate relief. Under the approved settlement agreement, Yankee Atomic agreed to reduce its revenue requirements by $79.0 million for the period 2006-2010 and to increase its revenue requirements by $47.0 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.

NOTE 5 - DISCONTINUED OPERATIONS

Catamount On December 20, 2005, CRC completed the sale of Catamount to CEC Wind Acquisition, LLC, a Delaware limited liability company established by Diamond Castle Holdings, a New York-based private equity investment firm ("Diamond Castle"). Cash proceeds from the sale amounted to $59.25 million, resulting in an after-tax gain of $5.6 million in 2005. Components of the gain were as follows (in thousands):

Cash proceeds	$59,250
SAB 51 gain on Oct. 31, 2005 stock issuance	952
Net book value of investment	(47,681)
Sale-related costs	(1,455)
Contingent liability	(276)
Income tax liability	(5,183)
After-tax gain on Dec. 20, 2005 sale	$5,607

The Company agreed to indemnify Catamount and Diamond Castle, and certain of their respective affiliates, in respect of a breach of certain representations, warranties and covenants as described in Note 17 - Commitments and Contingencies.

A fourth quarter 2006 true-up of estimated federal income taxes related to the 2005 gain on the Catamount sale resulted in income from discontinued operations of $0.3 million. Catamount's operating expenses shown in the table below include $0.5 million in 2005 and 2004 of costs reallocated to continuing operations. Income from discontinued operations related to Catamount as of December 31 are summarized below (in thousands).

	2006	2005	2004
Operating revenues	**$-**	$-	$-
Operating expenses	**-**	(315)	(315)
Operating Income	**-**	315	315
Other income and (deductions):			
Equity in earnings of non-utility investments	-	1,591	4,220
Gain on sale of non-utility investments	-	-	2,518
Other income	-	2,093	1,895
Other deductions	-	(4,951)	(6,674)
Benefit for income taxes	**251**	856	1,928
Total other income and (deductions)	**251**	(411)	3,887
Total interest expense	**-**	575	280
Net income (loss) from discontinued operations	**251**	(671)	3,922
Gain from disposal, net of $5,183 income tax	**-**	5,607	-
Income from discontinued operations	**$251**	$4,936	$3,922

Connecticut Valley On January 1, 2004, Connecticut Valley completed the sale of substantially all of its plant assets and its franchise to PSNH. Components of the sale transaction were recorded in both continuing and discontinued operations on the 2004 Consolidated Statement of Income. Income from discontinued operations included a gain on disposal of about $21 million pre-tax, or $12.3 million after-tax. In addition to the gain on disposal, the Company recorded a loss on power costs of $14.4 million pre-tax, or $8.4 million after-tax relating to termination of the power contract with Connecticut Valley. There are no remaining significant business activities related to Connecticut Valley. Its results of operations included in discontinued operations in 2004 follow (in thousands):

	2004
Operating revenues	$23
Operating expenses	-
Other operating expenses	43
Income tax benefit	(7)
Total operating expenses	36
Operating loss	(13)
Other expense, net	(1)
Net loss from discontinued operations	(14)
Gain from disposal, net of $8,706 income tax	12,354
Income from discontinued operations	$12,340

NOTE 6 - FINANCIAL INSTRUMENTS

The estimated fair values of the Company's financial instruments at December 31 follow (in thousands)

	2006		2005	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Power contract derivatives (includes current portion)	**$7,997**	**$7,997**	$17,912	$17,912
Preferred stock not subject to mandatory redemption	**$8,054**	**$5,690**	$8,054	$6,092
Preferred stock subject to mandatory redemption (includes current portion)	**$4,000**	**$4,105**	$6,000	$6,304
Long-term debt:				
First mortgage bonds	**$110,500**	**$114,360**	$110,500	$117,614
New Hampshire Industrial Development Authority Bonds	**$5,450**	**$5,409**	$5,450	$5,272

The estimated fair values of power contract derivatives are based on over-the-counter quotations 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. The fair values in both years were unrealized losses and therefore were recorded as liabilities on the Consolidated Balance Sheets.

The fair value of the Company's fixed rate securities is estimated based on quoted market prices for the same or similar issues with similar remaining time to maturity or on current rates offered to the Company. 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 monthly.

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

The Company's accounts receivable are not collateralized. As of December 31, 2006, about 15 percent of total accounts receivable are with wholesale entities engaged in the energy industry. The Company's special deposits primarily represent collateral deposits held by counterparties engaged in the energy industry. This industry concentration could affect the Company's overall exposure to credit risk, positively or negatively, since customers may be similarly affected by changes in economic, industry or other conditions. The Company believes the credit risk posed by industry concentration is offset by the diversification and creditworthiness of its retail electric customer base.

The Company's practice to mitigate credit risk from its energy industry concentration with wholesale entities is to deal with creditworthy power and transmission counterparties or obtain deposits or guarantees from their affiliates. The Company 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, the Company holds parental guarantees from two transmission customers and from two forward power sale counterparties.

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

NOTE 7 - INVESTMENT SECURITIES

Available-for-Sale Securities The Company liquidated its bond portfolio at the end of 2006. While it held the portfolio it evaluated the carrying value on a quarterly basis, or when events and circumstances warranted evaluation to determine whether a decline in fair value was considered temporary or other-than-temporary. Several criteria were considered in evaluating other-than-temporary declines, including: 1) length of time and extent to which market value has been less than cost; 2) financial condition and near-term prospects of the issuer; and 3) intent and ability to retain investments in the issuer for a period of time sufficient to allow for any anticipated recovery in market value.

The Company recorded $0.2 million of realized gains on available-for-sale securities in 2006. The Company also recorded a nominal amount of impairments in 2006 based on expectations that certain securities would be redeemed prior to maturity. The Company recorded $0.1 million of realized losses and $0.3 million of impairments on available-for-sale securities in 2005. Additional information regarding available-for-sale securities at December 31, 2005 follows (in thousands):

Security Types	Amortized Cost	Unrealized Gains	Unrealized Losses	Estimated Fair Value
Current Assets:				
Debt Securities:				
US Government Agencies	$12,355	$82	$(47)	$12,390
Corporate Bonds	4,732	29	(19)	4,742
Auction Rate Securities	27,100	-	-	27,100
Subtotal	44,187	111	(66)	44,232
Equity Securities:				
Auction Rate Securities	28,200	-	-	28,200
Subtotal current assets	72,387	111	(66)	72,432
Investments and Other Assets:				
Debt Securities:				
US Government Agencies	3,973	1	(31)	3,943
Corporate Bonds	1,504	3	-	1,507
Subtotal investments and other assets	5,477	4	(31)	5,450
Total available-for-sale securities	$77,864	$115	$(97)	$77,882

Millstone Decommissioning Trust Fund The Company has decommissioning trust fund investments related to its 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. Since regulatory authorities limit the Company's ability to oversee the day-to-day management of its nuclear decommissioning trust fund investments, the Company does not have the ability to hold individual securities in the trusts. 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 the impairment is concluded to be other-than-temporary. In 2006, the Company changed its method of assessing other-than-temporary declines and considers all securities held by its nuclear decommissioning trusts with fair values below their cost basis to be other-than-temporarily impaired. As a result, an impairment loss of $13,000 was recognized and recorded to Other deferred credits - regulatory on the Consolidated Balance Sheet.

Prior to 2006, unrealized losses on available-for-sale securities shown below, both on an individual and aggregate basis, were minor when compared to the original costs; therefore, such unrealized losses were considered temporary.

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

	2006				2005			
Security Types	**Amortized Cost**	**Unrealized Gains**	**Unrealized Losses**	**Estimated Fair Value**	Amortized Cost	Unrealized Gains	Unrealized Losses	Estimated Fair Value
Equity Securities	**$2,439**	**$1,601**	-	**$4,040**	$2,415	$1,151	$(15)	$3,551
Debt Securities	**1,382**	**14**	-	**1,396**	1,283	22	(13)	1,292
Cash and other	**40**	-	-	**40**	42	-	-	42
Total	**$3,861**	**$1,615**	-	**$5,476**	$3,740	$1,173	$(28)	$4,885

Information related to the fair value of debt securities at December 31, 2006 follows (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	$29	$329	$318	$720	$1,396

The table below presents the gross unrealized losses and fair value of certain investments, aggregated by investment category and the length of time these numerous securities have been in a continuous loss position at December 31, 2005 (in thousands):

	Equity Securities		Debt Securities	
	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
Less than 12 months	$4	-	$597	$(9)
12 months or more	193	$(15)	105	(4)
Total	$197	$(15)	$702	$(13)

NOTE 8 - RETAIL RATES AND REGULATORY ACCOUNTING

Retail Rates The Company recognizes adequate and timely rate relief is required to maintain its financial strength, particularly since its rates do not have fuel or power cost adjustment mechanisms.

The Company's retail rates at December 31, 2006 are based on a March 29, 2005 PSB Order ("2005 Rate Order") that included, among other things: 1) a 2.75 percent rate reduction beginning April 1, 2005; 2) a $6.5 million pre-tax refund to customers; 3) a 10 percent return on equity (reduced from 11 percent); and 4) a requirement that the gain related to the 2004 Connecticut Valley sale be applied to the benefit of ratepayers to compensate for increased costs. The 2005 Rate Order resulted in a $21.8 million pre-tax charge to utility earnings in the first quarter of 2005. The primary components of the charge to earnings included: 1) a revised calculation of overearnings for the period 2001 - 2003; 2) application of the gain from the Connecticut Valley sale to reduce costs; 3) a customer refund for the period April 7, 2004 through March 31, 2005; and 4) amortization of costs and other adjustments.

On June 22, 2005, the Company filed an appeal of portions of the 2005 Rate Order with the Vermont Supreme Court. The issues that were raised on appeal primarily focused on whether the 2005 Rate Order set rates retroactively without statutory authorization. On July 18, 2006, the Court issued its decision rejecting the Company's appeal. The Court's decision had no effect on the Company's financial condition or results of operations for 2006.

On May 15, 2006, the Company filed a request for a 6.15 percent rate increase (additional revenue of $16.4 million on an annual basis), to be effective February 1, 2007. On September 11, 2006, the Company and the DPS reached a settlement in the case, agreeing to a 3.73 percent increase effective January 1, 2007. The agreement reduced the Company's proposed allowed rate of return on common equity from 12 percent to 10.75 percent. On November 6, 2006, the Company and DPS filed amended testimony with the PSB to settle the Company's Accounting Order request related to recovery of fourth quarter 2005 replacement energy costs associated with a Vermont Yankee scheduled refueling outage. The agreement included recovery of incremental replacement energy costs of $1.5 million over a two-year period and added 0.34 percent to the Company's rate increase request, resulting in a combined rate increase request of 4.07 percent effective January 1, 2007.

On December 7, 2006, the PSB issued an Order ("2006 Rate Order") approving the 4.07 percent rate increase effective January 1, 2007. The 2006 Rate Order provided, among other things, an allowed rate of return on common equity of 10.75 percent capped until the Company's next rate proceeding. The January 1, 2007 rate increase, net of amounts to be returned to customers as described below, will add revenue of approximately $9.9 million annually.

The Company's Accounting Order request for recovery of the $1.5 million of incremental replacement power costs described above was subject to PSB approval. The 2006 Rate Order requires the Company to record a regulatory asset or liability for any difference between the replacement power cost amortization included in the 4.07 percent rate increase and the amount approved by the PSB. On January 12, 2007, the PSB issued an Order denying the Company's Accounting Order request. This 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. Instead, the Company will defer the $1.5 million of revenue over two years and continue such deferral until its next rate proceeding, at which time the total amount deferred will be returned to customers.

Regulatory Accounting Under SFAS No. 71, the Company accounts for certain transactions in accordance with permitted regulatory treatment such that regulators may permit incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when recovered in future revenues. Regulatory assets and certain other deferred credits are being amortized in accordance with the 2005 Rate Order. These items, including other deferred credits, are also adjusted upward or downward in accordance with permitted regulatory treatment.

In the event that the Company no longer meets the criteria under SFAS No. 71 and there is not a rate mechanism to recover these costs, the Company would be required to write off $20.5 million of regulatory assets (total regulatory assets of $52.2 million less pension and postretirement medical costs of $31.7 million), $12.1 million of other deferred charges - regulatory and $12.7 million of other deferred credits - regulatory. This would result in a total extraordinary charge to operations of $19.9 million pre-tax as of December 31, 2006. The Company would also be required to record pension and postretirement costs of $31.7 million on a pre-tax basis to Accumulated Other Comprehensive Loss as a reduction in stockholder's equity, and would be required to determine any potential impairment to the carrying costs of deregulated plant.

The table below provides a summary of Regulatory assets, Other deferred charges - regulatory and Other deferred credits - regulatory on the Consolidated Balance Sheets at December 31 (in thousands):

	2006	2005
Regulatory assets		
Pension and postretirement medical costs - SFAS No. 158	**$31,705**	$-
Nuclear plant dismantling costs	**15,033**	$20,995
Nuclear refueling outage costs - Millstone	**308**	1,538
Income taxes	**3,810**	3,810
Vermont Yankee sale costs (non-tax)	**496**	2,481
Vermont Yankee fuel rod maintenance deferral	**231**	1,154
Asset retirement obligations	**501**	384
Other	**95**	82
Regulatory assets	**52,179**	30,444

Other deferred charges - regulatory		
Vermont Yankee sale costs (tax)	**3,130**	3,130
Unrealized loss on power contract derivatives	**7,997**	17,912
Tree trimming and pole treating	**710**	3
Other	**290**	-
Other deferred charges - regulatory	**12,127**	21,045
Other deferred credits - regulatory		
Vermont utility overearnings 2001 - 2003	**4,803**	8,646
Connecticut Valley gain on termination of power contract	**554**	2,770
Asset retirement obligation - Millstone Unit #3	**3,055**	1,337
Vermont Yankee IRS settlement	**1,088**	1,088
Emission allowances and renewable energy credits	**924**	481
Environmental remediation	**1,648**	-
Other	**615**	1,102
Other deferred credits - regulatory	**12,687**	15,424

Regulatory assets included in the table above are being recovered in retail rates, except for the asset retirement obligations. The recovery period for regulatory assets varies based on the nature of the costs. The recovery period for the Vermont Yankee sale costs and fuel rod maintenance deferral ends December 2007. All regulatory assets are earning a return, except for income taxes, asset retirement obligations, nuclear dismantling costs that have not yet been incurred by the Company, and pension and postretirement medical costs. Most items listed in other deferred credits - regulatory are being amortized for periods ranging from 2 to 3 years. Pursuant to the 2005 Rate Order, 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.

Pension and postretirement medical costs are related to adoption of SFAS No. 158 as described in Note 15 - Pension and Postretirement Medical Benefits. Environmental remediation represents the portion of a reduction in environmental reserves that is attributable to ratepayers as described in Note 17 - Commitments and Contingencies.

NOTE 9 - SHARE-BASED COMPENSATION

The Company has awarded share-based compensation to key-employees and non-employee directors under several stock compensation plans. Awards under these plans have been comprised of three primary types: 1) stock options; 2) common stock that vests immediately or cliff vests based on service conditions; and 3) performance shares that vest based on performance, market and service conditions. These are described in more detail below.

Summarized information about share-based compensation plans at December 31, 2006 follows:

Plan	Shares Authorized	Stock options outstanding	Shares Available for future grant
1988 Stock Option Plan - Key Employees	334,375	-	-
1997 Stock Option Plan - Key Employees	350,000	174,458	-
1998 Stock Option Plan - Non-employee Directors	112,500	6,975	-
2000 Stock Option Plan - Key Employees	350,000	190,680	-
2002 Long-Term Incentive Plan	350,000	149,669	95,669
Total	1,496,875	521,782	95,669

The 2002 Long-Term Incentive Plan ("2002 LTIP") authorizes the granting of stock options, stock appreciation rights, common shares and performance shares. Stock option grants were eliminated as a form of compensation to key-employees and non-employee directors effective January 1, 2006. The Company has not granted stock appreciation rights as a form of compensation.

Total share-based compensation expense recognized in the income statement for the last three years was $0.9 million in 2006, $0.1 million in 2005 and $0.3 million in 2004. The total income tax benefit recognized in the income statement for share-based compensation was $0.3 million in 2006, less than $0.1 million in 2005 and $0.1 million in 2004. No compensation costs were capitalized. Cash received from exercise of stock options was $1.3 million in 2006, and the tax benefit realized for the tax deductions from option exercises was $0.1 million. This amount is included in Other Paid in Capital on the Consolidated Balance Sheet.

Currently, the Company settles stock options that are exercised and other stock awards from authorized but un-issued 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 the Company's Board of Directors. Historically, these awards have been settled in the form of shares of the Company's common stock.

Stock Options As described above, the Company no longer grants stock options as a form of compensation. All stock options that are outstanding 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. The fair value in both years was estimated using the Black-Scholes option pricing model with the assumptions shown in the table below. The volatility assumption was based on the historical volatility of the Company's common stock over a period equal to the option's expected term. The risk-free rate of return was based on the yield at the date of grant of a U.S. Treasury security with a maturity period approximating the option's expected term. The dividend yield assumption was based on historical dividend payouts. The expected term of options granted was based on historical experience.

	2005	2004
Volatility	25.82%	25.51%
Risk-free rate of return	4.35%	3.55%
Dividend yield	5.11%	5.74%
Expected life in years	5.04	5.81

The stock options granted during 2005 had a weighted-average grant date fair value of $3.55, and $2.82 in 2004. A summary of stock option activity during 2006 follows.

	Shares	**Weighted Average Exercise Price**
Options outstanding and exercisable at January 1	652,321	$17.02
Exercised	(79,335)	$15.97
Granted	-	-
Forfeited	(46,704)	$20.00
Expired	(4,500)	$16.23
Options outstanding and exercisable at December 31	521,782	$16.92

The total intrinsic value of stock options exercised during the last three years was $0.3 million in 2006, $0.1 million in 2005 and $0.4 million in 2004. The aggregate intrinsic value of options outstanding and exercisable as of December 31, 2006 was $3.5 million. Additional information regarding stock options outstanding and exercisable at December 31, 2006 follows:

		Weighted Average	
Range of Exercise Prices	**Number Options**	**Remaining Contractual Life (Years)**	**Exercise Price**
$10.5625 - $11.7894	106,760	2.0	$10.7696
$14.2436 - $15.4706	59,500	1.4	$14.6250
$15.4707 - $16.6976	39,900	4.3	$16.1050
$16.6977 - $17.9247	82,830	5.8	$17.4827
$17.9248 - $19.1517	42,800	5.4	$19.0750
$19.1518 - $20.3788	129,915	6.3	$20.1107
$20.3789 - $21.6058	60,077	6.9	$21.4916
	521,782	4.6	$16.9245

Common Stock and Nonvested Shares Under the 2002 LTIP, common stock can be granted to key employees and non-employee directors. The fair value of these awards is equal to the market value of the Company's 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 2006 follows:

	Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1	892	$22.41
Granted	20,734	$21.42
Vested	(19,953)	$22.36
Deferred	(673)	$20.42
Forfeited	-	-
Nonvested at December 31	1,000	$18.15

Common stock granted in 2006 included 12,740 shares to the Company's Directors as part of their annual retainer. These shares vest immediately, and individual directors can elect to defer receipt of their retainer under the terms of the Deferred Compensation Plan for Directors and Officers. A total of 2,494 shares were granted to the directors that resigned in 2006 as part of the Company's Board Restructuring Agreement Resolution. The remaining 5,500 shares were granted to certain executive officers. The fair value of shares vested in 2006 totaled $0.4 million. Compensation expense was $0.4 million in 2006, $0.2 million in 2005 and $0.1 million in 2004. Unearned compensation expense at December 31, 2006 was of a nominal amount.

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 the Company's performance compared to pre-established performance targets for relative Total Shareholder Return ("TSR") compared to all publicly-traded electric and combined utilities and operational measures beginning with the 2005 performance cycle. 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 with respect to performance shares 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.

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 2006 was $18.49 per share. Compensation cost is recognized over the three-year vesting life, based on the shares that ultimately vest, and is adjusted for the actual target percentage achieved. The fair value of performance shares for TSR measures was estimated on the date of grant using a Monte Carlo simulation model. The grant-date fair value of performance shares with TSR measures granted in 2006 was $16.50 per share. Compensation cost is recognized on a straight-line basis over the three-year vesting life and is not adjusted for the actual target percentage achieved. The weighted-average assumptions used in the Monte Carlo valuation for TSR performance shares granted in 2006 are shown in the table below.

Volatility	**23.10%**
Risk-free rate of return	**4.29%**
Dividend yield	**4.98%**
Term (years)	**3.0**

The volatility assumption was based on the historical volatility of the Company's 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 date of grant 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. The weighted-average assumptions used in the Monte Carlo valuation for the TSR performance shares granted in 2004 and 2005 were the same as those used for stock options described above with the exception of a 3-year term.

A summary of performance share activity during 2006 follows:

	Shares	Weighted Average Grant-Date Fair Value
Outstanding at January 1	42,158	$20.82
Granted (a)	38,460	$17.50
Vested	-	-
Forfeited (b)	(16,590)	$21.18
Outstanding at December 31 (c)	64,028	$18.73

(a) Includes 4,660 shares for estimated dividend equivalents.
(b) Performance shares under the 2004 - 2006 performance cycle, because targeted financial goals were not achieved.
(c) The number of common shares related to performance shares may range from zero to 150 percent of the number shown in the table above based on the achievement of operational and TSR measures relative to the three-year performance cycles.

The Company recorded compensation expense for performance share plans of $0.5 million in 2006 and $0.2 million in 2004. The Company recorded a $0.1 million credit to compensation expense in 2005 reflecting the reversal of amounts previously expensed because targeted financial goals were not achieved. Unrecognized compensation expense related to outstanding performance shares as of December 31, 2006 amounted to $0.5 million and is expected to be recognized over a weighted-average period of 1.5 years.

NOTE 10 - TREASURY STOCK

Shares of common stock purchased by the Company are recorded at cost and result in a reduction of shareholders' equity on the Consolidated Balance Sheet. On February 7, 2006, the Company's Board of Directors authorized the repurchase of 2,250,000 shares of the Company's common stock in a reverse Dutch tender offer using proceeds from the December 20, 2005 sale of Catamount. Under the procedures of the tender offer, shareholders could offer to sell some or all of their stock to the Company at a target price in a range from $20.50 to $22.50 per share. The tender offer commenced on February 14, 2006 and ended on April 5, 2006. Upon conclusion of the tender offer, the Company purchased 2,249,975 shares, about 18.3 percent of its common shares outstanding, at $22.50 per share. Cash paid for the common shares, including transaction costs, amounted to $51.2 million.

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

The Company's preferred and preference stock not subject to mandatory redemption at December 31 consisted of the following (in thousands):

	2006	2005
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
Preferred stock, $25 par value, authorized 1,000,000 shares, none outstanding	**-**	-
Preference stock, $1 par value, authorized 1,000,000 shares, none outstanding	**-**	-
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, 2006, a total of 120,538 shares were outstanding, including 80,538 that are not subject to mandatory redemption and are listed in the table above, and 40,000 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 the Company's capital stock or any other security. No preferred and preference stock not subject to mandatory redemption was issued or redeemed in the last three years.

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, and 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 the Company's 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 the option of the Company upon vote of at least three-quarters of its 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 the affairs of the Company. At December 31, 2006, 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

The Company has one series of Preferred Stock, $100 Par Value that is subject to mandatory redemption, 8.3 Percent Series Preferred Stock, with shares outstanding of 40,000 at December 31, 2006, 60,000 at December 31, 2005 and 80,000 at December 31, 2004. 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, 2006 premiums payable in the event of voluntary liquidation, dissolution or winding up of the affairs of the Company are at $2.490 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 $1.0 million (10,000 shares at par value) per annum. The Company, at its option, may also redeem at par an additional non-cumulative $1.0 million per annum. The Company is scheduled to make annual payments of $1.0 million in 2007, 2008, 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 2006, the Company paid its Transfer Agent $1.0 million for the mandatory redemption payment that is effective January 1, 2007. In the fourth quarter of 2005, the Company paid its Transfer Agent $2.0 million for the mandatory and optional sinking fund payments that were effective January 1, 2006. 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 $0.3 million in 2006, $0.5 million in 2005 and $0.7 million in 2004.

NOTE 13 - LONG-TERM DEBT AND CREDIT FACILITY

The Company's long-term debt at December 31 consisted of the following (in thousands):

	2006	2005
First Mortgage Bonds		
6.27%, Series NN, due 2008	**$3,000**	$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
8.91%, Series JJ, due 2031	**15,000**	15,000
New Hampshire Industrial Development Authority Bonds		
Variable 3.75%, due 2009	**5,450**	5,450
Total long-term debt	**$115,950**	$115,950

Long-Term Debt: Substantially all of the Company's utility property and plant is subject to liens under the Company's First Mortgage Bonds. The First Mortgage Bonds are callable at the Company's 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 Company's New Hampshire Industrial Development Authority Bonds are pollution control revenue bonds and the interest rate resets every five years. These bonds are callable at the option of the Company or the bondholders every five years on the rate reset date. The last rate reset date occurred on December 1, 2004. As of December 31, 2006, the bonds are only callable at the option of the Company in special circumstances involving unenforceability of the indenture or a change in the usability of the project.

The Company's debt financing documents do not contain cross-default provisions to affiliates outside of the consolidated entity. Certain of the Company's debt financing documents contain cross-default provisions to its wholly owned subsidiaries, East Barnet, CV Realty 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, the Company is not in default under any of its debt financing documents. Scheduled sinking fund payments and maturities for the next five years are $0 in 2007, $3.0 million in 2008, $5.5 million in 2009, $0 in 2010 and $20.0 million in 2011.

Letters of Credit: The Company has 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 Long-Term Debt and $10.8 million is included in Notes Payable. These letters of credit, which expired on November 30, 2006, were extended by the bank to November 30, 2007. The letters of credit are secured under the Company's first mortgage indenture. At December 31, 2006, there were no amounts drawn under these letters of credit.

Credit Facility: The Company has a three-year, $25.0 million unsecured revolving credit facility with a lending institution pursuant to a Credit Agreement dated October 21, 2005. 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 on the unused balance, plus interest on the outstanding balance of amounts borrowed and letters of credit based on our unsecured long-term debt rating. Terms also include the requirement to collateralize any outstanding letters of credit in the event of a default under the credit facility. This facility also 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 the Company's credit rating is below investment grade, therefore it has been in effect for the Company since October 2005. The MAE clause could allow the lending institution to deny a transaction under the credit facility at the point of request. Once any funding is advanced, its maturity cannot be accelerated for reasons other than an event of default. At December 31, 2006 no amounts were outstanding under this facility, but the Company did issue a $4.5 million letter of credit to support certain power-related performance assurance requirements. No amounts have been drawn under that letter of credit, which expires in September 2008.

Covenants: The Company's long-term debt indentures, letters of credit, and credit facility contain financial and non-financial covenants. The most restrictive financial covenants include maximum debt to total capitalization of 50 percent, and minimum interest coverage of 1.75 times. At December 31, 2006, the Company was in compliance with all covenants.

Dividend and Optional Stock Redemption Restrictions: The Company's $25.0 million revolving credit facility restricts optional redemptions of capital stock. The First Mortgage Bond indenture and the Company's 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, about $49.1 million of retained earnings was not subject to such restriction at December 31, 2006. 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. The Company's Articles of Association also contain a covenant that requires the Company to maintain a minimum common equity level of about $3.3 million as long as any Preferred Stock is outstanding.

NOTE 14 - NOTES PAYABLE

The Company's notes payable at December 31 consisted of the following (in thousands):

	2006	2005
Vermont Industrial Development Authority Bonds		
Variable, due 2013 (3.69% at December 31, 2006)	**$5,800**	$5,800
Connecticut Development Authority Bonds		
Variable, due 2015 (3.61% at December 31, 2006)	**5,000**	5,000
Total Notes Payable	**$10,800**	$10,800

These bonds are floating rate, monthly demand, pollution-control, revenue 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 the option of the Company or bondholders 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. The Company has outstanding secured short-term letters of credit that support these bonds, as described in Note 13 - Long-Term Debt and Credit Facility.

NOTE 15 - PENSION AND POSTRETIREMENT MEDICAL BENEFITS

The Company has a qualified, non-contributory, defined-benefit, trusteed pension plan ("Pension Plan") covering all employees (union and non-union). 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. The Company's funding policy is to contribute an amount equal to the annual actuarial cost or at least a statutory minimum to a trust. The Company is not required by its union contract to contribute to multi-employer plans. At the end of 2005, the Company adopted the RP-2000 mortality table that replaced the GAM 94 table.

The Company also sponsors 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. The Company funds this obligation through a Voluntary Employees' Benefit Association and 401(h) Subaccount in its Pension Plan. Retirees under the age of 65 ("Pre-65 retirees") participate in plan options similar to active employees. Retirees at or over the age of 65 ("Post-65 retirees") receive limited coverage with a $10,000 annual individual maximum. Retiree contributions for Post-1995 retirees are 100 percent of the increase in the cost over 1995 levels and there are no retiree contributions for Pre-1996 retirees.

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, 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 Company's pension and postretirement benefit obligations and plan assets are valued annually as of a September 30 measurement date.

Based on historical recovery of pension and other postretirement medical costs, the Company has recognized a regulatory asset for certain of its pension and postretirement medical costs versus recording a charge to accumulated other comprehensive loss ("AOCI"). A charge was recorded to AOCI related to the Company's non-qualified pension plan and its unregulated subsidiaries. At December 31, 2006, the effect on individual financial statement line items related to applying this standard are as follows (in thousands):

	Before the Adoption of SFAS No. 158	Adjustment	After the Adoption of SFAS No. 158
Assets:			
Current assets			
Deferred income taxes	$2,775	$124	$2,899
Total current assets	$68,443	124	$68,567
Deferred charges and other assets			
Regulatory assets	$20,473	31,706	$52,179
Other	$6,797	(1,103)	$5,694
Total Assets	**$470,211**	**$30,727**	**$500,938**
Capitalization and Liabilities:			
Capitalization			
Accumulated other comprehensive loss	$(109)	$(435)	$(544)
Total common stock equity	$179,787	(435)	$179,352
Current liabilities			
Other current liabilities	$19,452	306	$19,758
Deferred credits and other liabilities			
Deferred income taxes	$32,640	(173)	$32,467
Accrued pension and benefit obligations	$6,518	31,029	$37,547
Total Capitalization and Liabilities	**$470,211**	**$30,727**	**$500,938**

Benefit Obligation The changes in benefit obligation for pension and postretirement medical benefits at December 31 follow (in thousands):

	Pension Benefits		Postretirement Medical Benefits	
	2006	2005	**2006**	2005
Benefit obligation at beginning of measurement date	**$104,250**	$96,350	**$30,300**	$24,491
Service cost	**3,686**	3,227	**706**	512
Interest cost	**5,971**	5,856	**1,696**	1,444
Actuarial loss (gain)	**(2,546)**	4,713	**(4,678)**	5,829
Plan participants' contributions	**-**	-	**727**	504
Gross benefits paid	**(7,508)**	(5,896)	**(2,629)**	(2,480)
less: federal subsidy on benefits paid	**-**	-	**154**	-
Projected obligation as of measurement date (September 30)	**$103,853**	$104,250	**$26,276**	$30,300
Accumulated obligation as of measurement date (September 30)	**$83,549**	$84,415	**-**	-

The reduction in the Company's accumulated postretirement benefit obligation due to the impact of the Medicare Part D subsidy is $3.6 million for 2006 and $2.0 million for 2005.

The present value of future Postretirement Plan participants' contributions was $34.6 million for 2006 and $30.7 million for 2005.

Benefit Obligation Assumptions Weighted-average assumptions used to determine benefit obligations at the September 30 measurement date 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. As of September 30, 2006, the following weighted-average assumptions for pension and postretirement medical benefits were used in determining the Company's related liabilities at December 31:

	Pension Benefits		Postretirement Medical Benefits	
	2006	2005	**2006**	2005
Discount rates	**5.95%**	5.65%	**5.80%**	5.65%
Rate of increase in future compensation levels	**4.25%**	4.00%	**4.25%**	4.00%

For measurement purposes, a 10.5 percent annual rate of increase in the per capita cost of covered health care benefits was assumed for fiscal 2006, for pre-65 and post-65 claims costs. The rate is assumed to decrease 1 percent in each of the five subsequent years until the ultimate trend rate of 5.5 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 (in thousands):

	1-Percentage Point Increase	1-Percentage Point Decrease
Effect on postretirement medical benefit obligation as of September 30, 2006	$2,157	$(1,813)
Effect on aggregate service and interest costs	$259	$(210)

Asset Allocation The asset allocations at the measurement date for 2006 and 2005, and the target allocation for 2007, by asset category, are as follows:

	Pension Plan			Postretirement Medical Plan		
	2007 Target	**2006**	2005	**2007 Target**	**2006**	2005
Equity securities	**67.0%**	**65.9%**	68.8%	**67.0%**	-	-
Debt securities	**33.0%**	**34.1%**	31.2%	**33.0%**	-	-
Other	-	-	-	-	**100.0%**	100.0%
Total	**100.0%**	**100.0%**	100.0%	**100.0%**	**100.0%**	100.0%

Investment Strategy The Company's pension investment policy seeks to achieve sufficient growth to enable the Pension Plan to meet its future benefit obligations to participants, to maintain certain funded ratios and minimize near-term cost volatility. Current guidelines specify generally that 67 percent of plan assets be invested in equity securities and 33 percent of plan assets be invested in debt securities. The asset allocation mix will be reassessed in 2007.

The Company's 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. During 2006, the plan assets were invested in cash equivalents. The Company plans to adopt an asset allocation mix in 2007 similar to that of its Pension Plan assets.

Plan Assets The changes in Plan assets as of the measurement date are shown below (in thousands):

	Pension Plan		Postretirement Medical Plan	
	2006	2005	**2006**	2005
Fair value of plan assets at beginning of measurement date	**$67,784**	$61,513	**$6,174**	$4,643
Actual return on plan assets	**5,091**	8,787	**369**	91
Employer contributions*	**20,764**	3,380	**6,885**	3,416
Plan participants' contributions	**-**	-	**727**	504
Gross benefits paid*	**(7,508)**	(5,896)	**(2,629)**	(2,480)
Fair value of assets as of measurement date (September 30)	**$86,131**	$67,784	**$11,526**	$6,174
* Includes benefits paid from employer assets			**$(1,902)**	$(1,976)

Funded Status The Plans' funded status was as follows (in thousands):

	Pension Plan		Postretirement Medical Plan	
	2006	2005	**2006**	2005
Fair value of assets	**$86,131**	$67,784	**$11,526**	$6,174
Benefit obligation	**(103,853)**	(104,250)	**(26,276)**	(30,300)
Company contributions between measurement and year-end dates	**-**	-	**593**	497
Funded Status	**(17,722)**	(36,466)	**(14,157)**	(23,629)
Unrecognized net actuarial loss	**-**	17,417	**-**	18,337
Unrecognized prior service cost	**-**	3,384	**-**	1
Unrecognized net transition obligation	**-**	-	**-**	1,791
Accrued benefit cost	**$(17,722)**	$(15,665)	**$(14,157)**	$(3,500)

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

	Pension Benefits		Postretirement Medical Benefits	
	2006	2005	**2006**	2005
Noncurrent liability	**$(17,722)**	-	**$(14,157)**	-
Accrued benefit cost	**-**	$(15,665)	**-**	$(3,500)
Additional minimum liability	**-**	(966)	**-**	-
Intangible asset	**-**	966	**-**	-
Net amount recognized	**$(17,722)**	$(15,665)	**$(14,157)**	$(3,500)

In 2006, the Postretirement Medical Plan noncurrent liability shown above included an actuarial estimate of $0.2 million related to the Company's Medicare D subsidy payments expected in the first quarter of 2007.

The amounts recognized in Regulatory assets and AOCI in the Company's Consolidated Balance Sheet at December 31, 2006 consisted of (in thousands):

	Pension Benefits			Postretirement Medical Benefits		
	Regulatory Asset	**AOCI**	**Total**	**Regulatory Asset**	**AOCI**	**Total**
Net actuarial loss	**$14,710**	**$28**	**$14,738**	**$12,391**	**$24**	**$12,415**
Prior service cost	**2,978**	**6**	**2,984**	**1**	**-**	**1**
Transition obligation	**-**	**-**	**-**	**1,532**	**3**	**1,535**
Net amount recognized	**$17,688**	**$34**	**$17,722**	**$13,924**	**$27**	**$13,951**

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

	Pension Benefits			Postretirement Medical Benefits		
	2006	2005	2004	**2006**	2005	2004
Net benefit costs include the following components						
Service cost	**$3,686**	$3,227	$3,021	**$706**	$512	$539
Interest cost	**5,971**	5,856	5,551	**1,695**	1,444	1,554
Expected return on plan assets	**(5,744)**	(5,267)	(5,624)	**(716)**	(477)	(432)
Amortization of actuarial loss	**785**	196	-	**1,591**	1,113	1,381
Amortization of prior service cost	**401**	401	394	**1**	1	1
Amortization of transition (asset) obligation	**-**	-	(146)	**256**	256	256
Net periodic benefit cost	**5,099**	4,413	3,196	**3,533**	2,849	3,299
Less amount allocated to other accounts	**885**	702	515	**613**	453	531
Net benefit costs expensed	**$4,214**	$3,711	$2,681	**$2,920**	$2,396	$2,768

Benefit Cost Assumptions Weighted-average assumptions used to determine net periodic costs at measurement date (September 30) are shown in the table below. The weighted-average assumptions shown for 2006, which were set at September 30, 2005, were used in determining 2006 expense. Likewise, the 2005 and 2004 weighted-average assumptions were used in determining 2005 and 2004 expense, respectively.

	Pension Benefits			**Postretirement Medical Benefits**		
	2006	2005	2004	**2006**	2005	2004
Weighted-average discount rates	**5.65%**	6.00%	6.00%	**5.65%**	6.00%	6.00%
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	**4.00%**	3.75%	3.75%	**4.00%**	3.75%	3.75%

2007 Cost Amortizations: The estimated amounts that will be amortized from regulatory assets and accumulated other comprehensive income into net periodic benefit cost in 2007 are as follows (in thousands):

	Pension Benefits	**Postretirement Medical Benefits**
Actuarial loss	$582	$1,050
Prior service cost	398	1
Transition benefit obligation	-	256
Total	$980	$1,307

Expected Long-Term Rate of Return on Plan Assets The Company expects an average annual long-term return on the pension asset portfolio of 8.25 percent, based on a representative allocation within the target asset allocation described above. In formulating this assumed rate of return, the Company 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.

The Pension Plan assets earned a rate of return for the Plan years ended September 30, of 8.2 percent for 2006, 15.6 percent for 2005 and 12.3 percent for 2004.

Based on the postretirement medical benefit plan investment policy described above, the Company expects an average annual long-term return for the postretirement portfolio of 8.25 percent. In formulating this assumed long-term rate of return, asset categories and expectations for future returns by asset category were considered.

Pension and postretirement medical benefit expenses for 2006 were based on an expected long-term rate of return on assets of 8.25 percent. The same percentage will be used to determine the 2007 expenses.

Trust Fund Contributions The Pension Plan currently meets the minimum funding requirements of the Employee Retirement Income Security Act of 1974. The Company's Pension Plan trust fund contributions were $12.2 million in March 2006 and $8.6 million in September 2006. The Company's Postretirement Medical Plan trust fund contributions were $4.1 million in March 2006, $0.9 million in September 2006 and $0.2 million in December 2006.

Expected Cash Flows The table below reflects the total benefits expected to be paid from the external Pension Plan trust fund or from the Company's assets, including both the Company's 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 2007, about $5.2 million will be paid from the Pension Plan trust fund and about $2.1 million of postretirement medical benefits will be paid from the Company's assets. Information about the expected cash flows for the Pension Plan and postretirement medical benefit plans is as follows (in millions):

	Pension Benefits	Postretirement Medical Benefits	
		Gross	Expected Federal Subsidy
Employer Contributions			
2007	$4.1	$2.5	-
Expected Benefit Payments			
2007	$5.2	$2.1	$0.2
2008	6.1	2.1	0.3
2009	6.7	2.2	0.3
2010	8.8	2.2	0.3
2011	7.5	2.3	0.3
2012 - 2016	49.3	11.8	2.0

As of October 1, 2006, the Medicare Part D subsidy reduced the postretirement benefit obligation by $3.6 million and reduced the 2006 net periodic benefit cost by $0.3 million. The estimated Medicare Part D subsidy included in the expected gross postretirement medical benefit payments is shown above.

Other

Long-term Disability The Company records nonaccumulating post-employment long-term disability benefits in accordance with SFAS No. 5. The year-end post-employment medical benefit obligations of $1.8 million in 2006 and $1.5 million in 2005 are reflected in the Company's Consolidated Balance Sheets as Accrued pension and medical benefit obligations, and $0.2 million was recorded as Other current liabilities in 2006. The pre-tax post-employment benefit costs charged to expense, including insurance premiums, were $0.6 million in 2006, $0.2 million in 2005 and $0.4 million in 2004.

401(k) Savings Plan The Company maintains a 401(k) Savings Plan for substantially all employees. This savings plan provides for employee pre-tax and post-tax contributions up to specified limits. The Company has matched employee pre-tax contributions up to 4 percent of eligible compensation after one year of service and the Company match increased to 4.25 percent on January 1, 2007. Eligible employees are at all times vested 100 percent in their pre-tax and post-tax contribution account and in their matching employer contribution. The Company's matching contributions amounted to $1.2 million in 2006, 2005 and 2004.

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

The accumulated year-end SERP benefit obligation, based on the same discount rate described above for pension, was $3.6 million in 2006 and $3.5 million in 2005 and is reflected in the Consolidated Balance Sheets as Accrued pension and benefit obligations, and $0.3 million was recorded as Other current liabilities in 2006. The accumulated SERP benefit obligation included a comprehensive gain of $0.3 million in 2006 and a comprehensive loss of $0.1 million in 2005. The pre-tax SERP benefit costs charged to expense totaled $0.6 million in 2006, $0.5 million for 2005 and $0.4 million for 2004. 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 by the Company through life insurance policies held by the Company's 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 the Company's Consolidated Balance Sheets was $7.1 million in 2006 and $6.3 million in 2005. Changes in cash surrender value are included in Other income on the Company's Consolidated Statements of Income. These pre-tax amounts were an increase of $0.2 million for 2006, a nominal decrease for 2005 and an increase of $0.4 million for 2004.

NOTE 16 - INCOME TAXES

The Company's income tax provision (benefit) from continuing operations for the years ended December 31 consisted of the following (in thousands):

	2006	2005	2004
Federal:			
Current	**$4,875**	$(679)	$3,618
Deferred	**3,144**	(1,187)	(2,199)
Investment tax credits, net	**(379)**	(379)	(379)
	7,640	(2,245)	1,040
State:			
Current	**1,311**	432	2,046
Deferred	**1,055**	(269)	(1,018)
	2,366	163	1,028
Total federal and state income taxes	**$10,006**	$(2,082)	$2,068
Federal and state income taxes charged to:			
Operating expenses	**$8,569**	$(2,264)	$834
Other income	**1,437**	182	1,234
	$10,006	$(2,082)	$2,068

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

	2006	2005	2004
Income (loss) before income tax	**$28,107**	$(672)	$9,561
Federal statutory rate	**35%**	35%	35%
Federal statutory tax expense	**9,838**	(235)	3,346
Increase (benefit) in taxes resulting from:			
Dividend received deduction	**(494)**	(520)	(340)
State income taxes net of federal tax benefit	**1,729**	69	805
Investment credit amortization	**(379)**	(379)	(379)
Renewable Electricity Production Credit	**(273)**	(196)	-
AFUDC equity	**194**	194	273
Life insurance	**(236)**	(191)	(345)
Income tax refunds	**-**	-	(930)
Change in estimate for tax contingencies	**(191)**	(741)	(598)
Other	**(182)**	(83)	236
Total income tax expense (benefit)	**$10,006**	$(2,082)	$2,068
Effective combined federal and state income tax rate	**35.6%**	309.8%	21.6%

The Company decreased its estimate for tax contingencies by $0.2 million in 2006, $0.7 million in 2005 and $0.6 million in 2004 due to a reduction in potential tax liabilities.

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. For the periods ended 2006 and 2005, there were no valuation allowances recorded.

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 (in thousands):

	2006	2005
Deferred tax assets - current		
Reserves for uncollectible accounts	**$692**	$1,228
Deferred compensation and pension	**698**	685
Environmental costs accrual	**131**	166
SFAS No. 5 loss accrual	**485**	485
401(k) contribution carryforward	**71**	499
Active Medical Accrual	**346**	289
SFAS No. 133 - derivative instruments	**630**	-
Other accruals	**475**	154
Total deferred tax assets - current	**3,528**	3,506
Deferred tax liabilities - current		
Property tax accruals	**319**	272
Prepaid insurance	**310**	35
Total deferred tax liabilities - current	**629**	307
Net deferred tax assets - current	**2,899**	3,199
Deferred tax assets - long term		
Equity investments	**1,348**	1,348
Accruals and other reserves not currently deductible	**1,438**	1,402
Deferred compensation and pension	**-**	1,283
Environmental costs accrual	**1,378**	2,033
Millstone decommissioning costs	**2,232**	2,044
Contributions in aid of construction	**2,119**	1,978
Revenue deferral - Vermont utility earnings	**1,947**	3,504
SFAS No. 5 - loss accrual	**3,877**	4,362
SFAS No. 133 - derivative instruments	**2,611**	-
SFAS No. 158 - benefit liability	**13,220**	-
SFAS No. 112 - retiree medical benefits	**467**	1,398
Connecticut Valley gain deferral	**225**	1,123
Total deferred tax assets - long term	**30,862**	20,475
Deferred tax liabilities		
Property, plant and equipment	**38,765**	40,123
Net SFAS No. 109 regulatory asset	**1,544**	1,544
Vermont Yankee sale	**3,331**	4,135
SFAS No. 158 - regulatory asset	**13,220**	-
SFAS No. 133 - derivative instruments	**3,241**	-
Decommissioning costs	**1,906**	1,888
Other	**1,322**	1,432
Total deferred tax liabilities - long term	**63,329**	49,122
Net deferred tax liabilities - long term	**32,467**	28,647
Net deferred tax liabilities	**$29,568**	$25,448

On June 7, 2004, the State of Vermont enacted legislation that reduced the state income tax rate from 9.75 percent to 8.9 percent effective January 1, 2006, and from 8.9 percent to 8.5 percent effective January 1, 2007. Deferred tax assets and liabilities were adjusted in 2004 to reflect the enacted income tax rate change. This rate change reduced regulatory tax assets by about $1.4 million, and increased income tax expense by about $0.2 million. Book and tax differences have to be estimated due to the fact that the tax rate changes occurred after 2004 and over a two-year period.

NOTE 17 - COMMITMENTS AND CONTINGENCIES

Nuclear Decommissioning Obligations The Company's obligations for decommissioning and other costs associated with Maine Yankee, Connecticut Yankee and Yankee Atomic are described in Note 4 - Investments in Affiliates. The Company also has a 1.7303 joint-ownership percentage in Millstone Unit # 3. As a joint owner of the Millstone Unit #3 facility, in which Dominion Nuclear Corporation ("DNC") is the lead owner with about 93.4707 percent of the plant joint-ownership, the Company is responsible for its share of nuclear decommissioning costs. The Company has an external trust dedicated to funding its joint-ownership share of future decommissioning costs. DNC has suspended contributions to the Millstone Unit #3 Trust Fund because the minimum NRC funding requirements are being met or exceeded. The Company has also suspended contributions to the Trust Fund, but could choose to renew funding at its own discretion as long as the minimum requirement is met or exceeded. If a need for additional decommissioning funding is necessary, the Company will be obligated to resume contributions to the Trust Fund.

The Price-Anderson Act ("Act") currently limits public liability from a single incident at a nuclear power plant to about $10 billion. The Energy Policy Act of 2005, enacted in August 2005, extends the Act, which expired in 2003, for 20 years and provides a framework for immediate, no-fault insurance coverage for the public in the event of a nuclear reactor accident. The Act consists of 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, referred to as secondary financial protection, 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 $95.8 million per reactor per incident, limited to a maximum annual assessment of $15 million. These assessments will be adjusted for inflation. Currently, based on its joint-ownership interest in Millstone Unit #3, the Company could become liable for about $0.3 million of such maximum assessment per incident per year. The Maine Yankee, Connecticut Yankee and Yankee Atomic plants have received exemptions from participating in the secondary financial protection program under the Act.

Long-Term Power Purchases

Vermont Yankee: The Company purchases its entitlement share of plant output through the PPA between ENVY and VYNPC. As of September 15, 2006, VYNPC's entitlement in Vermont Yankee plant output declined from 100 percent to 83 percent. The Company's entitlement share of VYNPC power remains at 35 percent therefore its entitlement of total plant output was reduced from 35 percent to 29 percent after completion of the plant uprate. The Company's purchase of plant output is similar to the amount it received before the uprate process began. One remaining secondary purchaser continues to receive a small percentage (less than 0.2 percent) of the Company's entitlement. ENVY has no obligation to supply energy to VYNPC over the amount the plant is producing, so entitlement holders 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.

Prices under the PPA range from $39 to $45 per megawatt hour. 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. If market prices rise, however, PPA prices are not adjusted upward in excess of the PPA price. Future purchases are expected to be $58.0 million in 2007, $59.0 million in 2008, $64.8 million in 2009, $61.0 million in 2010 and $62.6 million in 2011. A summary of the PPA, including estimated average amounts for 2007 through 2012, are shown in the table below. These 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.

	2006	Estimated Average 2007 - 2012
Average capacity acquired	180 MW	182 MW
Share of VYNPC entitlement	34.8269%	34.8269%
Annual energy charge per mWh	$41.07	$42.14
Average total cost per mWh	$41.78	$42.64
Contract period termination		March 2012

Prior to the change in the Company's entitlement percentage, the Company purchased a share of uprate power at market rates from mid-March through mid-September based on the terms of the PPA. These purchases amounted to \$8.4 million in 2006, and are included in Purchased Power - affiliates on the Consolidated Statement of Income.

The plant's last scheduled refueling outage was in the fourth quarter of 2005. The price that the Company paid for replacement power during the outage was significantly higher than what was being recovered in retail rates. Therefore the Company filed a request with the PSB for an Accounting Order to defer incremental replacement power costs for recovery in its next rate proceeding. On January 12, 2007, the PSB issued an Order denying the Company's request. The Order had no 2006 income statement impact since the incremental replacement power costs were previously expensed in 2005. The plant's next refueling outage is scheduled to occur in the second quarter of 2007. The Company entered into a forward contract to purchase replacement power during the 2007 outage. This forward purchase contract is a derivative and had a fair value of an unrealized loss of \$0.3 million at December 31, 2006.

On October 3, 2006, the Company purchased forced outage insurance for \$1.3 million, to cover additional costs, if any, of obtaining replacement power from other sources if the Vermont Yankee plant experiences unplanned outages between January 1 and December 31, 2007. The coverage applies to unplanned outages of up to 30 consecutive calendar days per outage event, and provides for payment to the Company of the difference between hourly spot market prices and the PPA price when the spot price is above the \$40/mWh PPA price. Under this coverage, the Company will receive payments on claims within 30 days of submitting proof of loss claims. The total maximum coverage is \$10.0 million, with a \$1.0 million total deductible.

On June 8, 2006, the plant received a new output rating of approximately 620 MW, a 20 percent increase in plant capacity. The uprate required prior approval by the NRC and by the PSB. The PSB's March 2004 approval of the uprate was conditioned on ENVY providing outage protection indemnification ("Ratepayer Protection Proposal" or "RPP") for times the uprate process causes reductions in output that reduce the value of the PPA. The Company's maximum right to indemnification under the RPP is \$2.8 million for the three-year period beginning in May 2004 and ending after completion of the uprate (or a maximum of three years). As of December 31, 2006, the Company has collected a nominal amount under the RPP. There are three separate issues associated with the uprate and RPP described below.

- On March 16, 2006, the Company, Green Mountain Power, ENVY and the DPS filed a settlement proposal with the PSB resolving all issues that were raised in a petition before the PSB regarding the RPP. The Company's share of the settlement is estimated to be \$1.6 million, including \$0.7 million for recovery of incremental replacement power costs associated with a June 2004 outage at the plant. The remainder is for costs incurred between November 4, 2004 and February 28, 2006, when the plant ran at a reduced level due to the uprate project. Pursuant to the 2005 Rate Order, any reimbursement associated with the June 2004 outage shall be recorded as a regulatory liability for return to ratepayers. The settlement is not effective until the PSB issues a final order. The Company cannot predict the timing or outcome of this matter at this time.
- The Company is a party to a PSB Docket that was opened in June 2006 because the DPS was seeking additional ratepayer protections in the event that plant output must be reduced due to problems with its steam dryer. On September 18, 2006, the PSB issued an order requiring ENVY to submit a proposal to provide additional ratepayer protections that will protect Vermont utilities and ratepayers if the plant is forced to reduce output because of uprate-related steam dryer problems. The DPS and ENVY reached an agreement in the compliance filing with the PSB, which will provide protections in the event of a derate. The protections will apply to incremental replacement power costs and will remain in effect for at least two months after the refueling outage during which the plant operates successfully with no steam dryer-related outages or derates. The compliance filing is pending approval before the PSB and is not effective until the PSB issues a final order. The Company cannot predict the outcome of this matter at this time, but it is not expected to have a material impact on the Company's financial position, results of operations or cash flows.
- The PPA between ENVY and VYNPC contains a formula for determining the entitlement to power following the uprate. VYNPC and ENVY are seeking to resolve certain differences in the interpretation of the formula. One issue is how much capacity VYNPC may bid into the ISO-New England market following the uprate; another issue is the percentage of plant output that would be delivered under the PPA in the event of a derate. The Company cannot predict the outcome of this matter at this time.

On April 26, 2006, the PSB approved ENVY's request for dry cask storage for spent nuclear fuel through 2012. ENVY had previously announced that it could be required to shut down the plant in 2007 or 2008 if dry cask storage of its spent fuel was not approved. If the Vermont Yankee plant is shut down for any reason prior to the end of its operating license, the Company would lose about 50 percent of its committed energy supply and would have to acquire replacement power resources for approximately 40 percent of its estimated power supply needs. Based on projected market prices at December 31, 2006, the incremental cost of lost power, including capacity, is estimated to average $42 million on an annual basis. Based on this estimate, the Company would require a retail rate increase of approximately 15 percent for full cost recovery. The Company is not able to predict whether there will be an early shutdown of the Vermont Yankee plant or whether the PSB will allow timely and full recovery of increased costs related to any such shutdown. However, an early shutdown could materially impact the Company's financial position and future results of operations if the costs are not recovered in retail rates in a timely fashion.

Hydro-Quebec: The Company is 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 the Company. The VJO Power Contract has been in place since 1987 and purchases began in 1990. Related contracts were subsequently negotiated between the Company and Hydro-Quebec, which 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 the Company's purchases under the contract end in 2016.

There are specific contractual provisions that provide that in the event any VJO member fails to meet its obligation under the contract with Hydro-Quebec, the remaining VJO participants, will "step-up" to the defaulting party's share on a pro-rata basis. As of December 31, 2006, the Company's obligation is about 47 percent of the total VJO Power Contract through 2016, which represents approximately $551 million, on a nominal basis.

In accordance with guidance set forth in FASB Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* ("FIN 45"), the Company is 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, the Company must assume that all members of the VJO simultaneously default in order to estimate the "maximum potential" amount of future payments. The Company believes 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, the Company estimates that its undiscounted purchase obligation would be about an additional $645 million for the remainder of the contract, assuming that all members of the VJO defaulted by January 1, 2007 and remained in default for the duration of the contract. In such a scenario, the Company would then own the power and could seek to recover its costs from the defaulting members or its 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.

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, a third sellback arrangement was negotiated whereby the Company received a reduction in capacity costs from 1995 to 1999, and Hydro-Quebec obtained two options. The first gives Hydro-Quebec the right, upon four years' written notice, to reduce capacity deliveries by 50 MW beginning as early as 2011, including the use of a like amount of the Company's 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 load factor of 75 to 50 percent due to adverse hydraulic conditions in Quebec. This second option can be exercised five times through October 2015. The Company has determined that the first option is a derivative, but the second is not because it is contingent upon a physical variable. The year-end estimated fair value of the first option was an unrealized loss of $3.7 million in 2006 and $5.0 million in 2005. Hydro-Quebec has not yet exercised these options.

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 of time. Hydro-Quebec has used all of its elections, resulting in a 65 percent load factor obligation from November 1, 2002 to October 31, 2005. The VJO elected to purchase at an

80 percent load factor for the contract year beginning November 1, 2005, and November 1, 2006. The VJO have now used all of their load factor elections. After the contract year ending October 31, 2007, the annual load factor will be at 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.

Total purchases from Hydro Quebec were $64.3 million in 2006, $58.4 million in 2005 and $56.9 million in 2004. A summary of the Hydro-Quebec contracts, including historic and projected charges for the years indicated, follows (dollars in thousands, except per kWh amounts):

	2006	Estimated Average 2007 - 2012	Estimated Average 2013 - 2016
Annual Capacity Acquired	**142.9MW**	144.5MW	(a)
Minimum Energy Purchase - annual load factor	**80%**	(b)	(b)
Energy Charge	**$29,282**	$30,988	$20,841
Capacity Charge	**35,015**	33,462	20,240
Total Energy and Capacity Charge	**$64,297**	$64,450	$41,081
Average Cost per kWh	**$0.064**	$0.067	$0.071

(a) Annual capacity acquired is projected to be about 116 MW for 2013 - 2014, and 19 MW for 2015 - 2016.
(b) Annual load factor is 80 percent for contract year ending October 31, 2007. Annual load factors are 75 percent for each contract year thereafter.

Independent Power Producers: The Company receives power from several Independent Power Producers ("IPPs"). These plants primarily 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 order approving a settlement reached by the Company, other parties and the DPS. The settlement was related to various legal proceedings and negotiations that began in 1999 to change the IPPs' contracts with VEPPI to reduce power costs for customers' benefit. Cost savings to all Vermont utilities are estimated to be about $6.0 million between 2007 and 2020, exclusive of savings that might result from implementation of IPP contract buy downs through securitization. The Company's share of the savings is about 39 percent and is expected to range from $0.2 million to $0.4 million annually for the years 2007 through 2011. In 2006, power purchases from IPPs amounted to 6.7 percent of total mWh purchased and 19.2 percent of purchased power expense. Total purchased power from IPPs was $24.0 million in 2006, $19.7 million in 2005 and $20.3 million in 2004. Estimated annual purchases from IPPs are expected to range from $18.1 million to $19.9 million for the years 2007 through 2011.

Joint-ownership The Company has joint-ownership interests in electric generating and transmission facilities that are included in Utility Plant on its Consolidated Balance Sheets. At December 31 these included (dollars in thousands):

	Fuel Type	Ownership	In Service Date	MW Entitlement	2006	2005
Wyman #4	Oil	1.7769%	1978	10.8	**$3,422**	$3,419
Joseph C. McNeil	Various	20.0000%	1984	10.8	**15,555**	15,575
Millstone Unit #3	Nuclear	1.7303%	1986	20.0	**77,162**	77,105
Highgate Transmission Facility		47.5200%	1985	N/A	**14,357**	14,302
					110,496	110,401
Less accumulated depreciation					**60,986**	58,141
					$49,510	$52,260

The Company's 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.

On November 28, 2005, the NRC renewed Millstone Unit #3's operating license extending the license expiration from November 2025 to November 2045. In May 2006, DNC announced that it is evaluating an undetermined level of power uprate not to exceed seven percent. A seven percent uprate would increase the Company's share of plant generation by 1.4 MW, and the Company would be obligated to pay its ownership share of the related costs. In January 2004, DNC filed, on behalf of itself and the two minority owners, including the Company, a lawsuit against the DOE seeking recovery of costs related to 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 is expected to be held in August 2008. The Company continues to pay its 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 its ownership interest.

Performance Assurance At December 31, 2006, the Company had posted $8.6 million of collateral under performance assurance requirements for certain of its power contracts, including a $4.5 million letter of credit issued under its $25.0 million revolving credit facility.

The Company is subject to performance assurance requirements associated with its power purchase and sale transactions through ISO-New England under the Financial Assurance Policy for NEPOOL members. At the Company's current credit rating of 'BB+', its credit limit with ISO-New England is zero and it is required to post collateral for all net purchase transactions. ISO-New England reviews collateral requirements on a daily basis. As of December 31, 2006, the Company had posted $3.5 million of collateral, of which $3.0 million is included in Restricted Cash on the Consolidated Balance Sheet and $0.5 million is included in Cash and Cash Equivalents since it was above the required amount.

The Company is currently selling power in the wholesale market pursuant to two third-party contracts. One contract extends through mid 2007 and the other through late 2008. The Company is required to post collateral with these counterparties under certain conditions defined in the contracts. As of December 31, 2006, the Company had posted $4.5 million in the form of a letter of credit, and $0.5 million included in Special Deposits on the Consolidated Balance Sheet.

The Company is subject to performance assurance requirements associated with power purchase and sale transactions through ISO-New York. Activity in this market has been limited. At December 31, 2006, the Company had posted $0.1 million of collateral, which is included in Restricted Cash on the Consolidated Balance sheet.

The Company is also subject to performance assurance requirements under its Vermont Yankee power purchase contract (the 2001 Amendatory Agreement). If ENVY, the seller, has commercially reasonable grounds to question the Company's ability to pay for its monthly power purchases, ENVY may ask VYNPC and VYNPC may then ask the Company to provide adequate financial assurance of payment. The Company has not had to post collateral under this contract.

At December 31, 2005, the Company had posted $19.1 million of collateral under these performance assurance requirements, including $2.4 million with ISO-New England and $16.7 million with two other counterparties. These amounts were included in Special Deposits on the 2005 Consolidated Balance Sheet.

Environmental Over the years, more than 100 companies have merged into or been acquired by the Company. 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 the Company 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. The Company believes that it is in compliance with all laws and regulations and has implemented procedures and controls to assess and assure compliance. Corrective action is taken when necessary. Below is a brief discussion of known material issues.

Cleveland Avenue Property The Cleveland Avenue property in Rutland, Vermont, was used by a predecessor to make gas from coal. Later, the Company sited various operations there. Due to the existence of coal tar deposits, polychlorinated biphenyl contamination and the potential for off-site migration, the Company 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 2006, the Company updated its cost estimate of remediation for this site considering technological advancement, improved understanding of the site and its contaminants, and the very low likelihood of site redevelopment in the foreseeable future. As a result, the Company's liability for site remediation is expected to range from a high of $2.3 million to a low of $0.9 million. Management believes that the most likely cost of the remediation effort is $1.5 million, which is $2.5 million less than the accrual at December 31, 2005. The revised cost estimate was based on an engineering evaluation of possible remediation scenarios, and a Monte Carlo simulation, which is a complex mathematical model using a broad range of possible outcomes and statistical information in determining the outcome with the highest likelihood of occurrence. The assumptions used in the Monte Carlo model required considerable judgment by Management. The reduction in cost estimate reflects updated site information, the availability of advanced remediation technology and the Company's intent to voluntarily clean up the site rather than await a state or federal mandate to complete cleanup.

Brattleboro Manufactured Gas Facility In the 1940s, the Company owned and operated a manufactured gas facility in Brattleboro, Vermont. The Company 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 the Company that its corrective action plan for the site was approved. That plan is now in place. In 2006, the Company updated the cost estimate of remediation for this site reflecting increased redevelopment activity in adjacent sites. While redevelopment plans for the area have not been finalized, the recent acquisition of an adjacent site by the Town of Brattleboro and other recent activity have helped to better define the probable timing and nature of work that will be required for remediation of this site. Prior to this time, there were several proposals for use of the site but none more likely than the other to occur. As a result of the revised cost estimate, the Company's liability for site remediation is expected to range from a high of $1.3 million to a low of $0.1 million. Management believes that the most likely cost of the remediation effort is $0.6 million, which is $0.7 million less than the accrual at December 31, 2005. The revised cost estimate for this site was based on a similar method of engineering evaluation and Monte Carlo simulation as described above. The reduction in cost estimate reflects the use and specific remediation-related costs for the scenario with the highest likelihood of occurrence. This previously unavailable information replaced scenarios and related remediation costs that were based on the limited site-specific information available before the Company completed a comprehensive site investigation.

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

The reserve for environmental matters described above amounted to about $2.1 million as of December 31, 2006 and $5.4 million as of December 31, 2005. The current and long-term portions are included as liabilities on the Consolidated Balance Sheets. The reserve represents management's best estimate of the cost to remedy issues at these sites based on available information as of the end of the reporting periods. To the Company'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 the Company for any other study or remediation.

In the third quarter of 2006 when the updated costs estimates were completed, the Company and DPS reached an agreement that a portion of the reduction in estimated remediation costs should be attributed to ratepayers, and that the Company should file an Accounting Order request with the PSB for approval of such treatment. As a result, the Company determined that regulatory treatment for the ratepayer portion was probable and recorded $1.6 million of the $3.2 million reduction in environmental reserves as a deferred credit, included in Other Deferred Credits - Regulatory on the Consolidated Balance Sheet. The remaining $1.6 million was recorded as a reduction in operating costs, included in Other Operation on the Consolidated Statement of Income. The Company has not yet submitted its request for an Accounting Order with the PSB.

Leases and support agreements

Capital Leases: The Company had obligations under capital leases of $7.5 million at December 31, 2006 and $7.1 million at December 31, 2005. 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. The Company accounts for capital leases under SFAS No. 13, *Accounting for Leases.* In accordance with SFAS No. 71 and based on the Company's 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 $7.5 million, $7.2 million is related to the Phase II Hydro-Quebec ("Phase II") transmission facilities and the remaining $0.3 million is related to several five-year equipment leases that provide for the use of certain information technology and office equipment.

The Company participated with other electric utilities in the construction of the Phase II transmission facilities throughout New England, which were completed at a total initial cost of $487 million. Under a support agreement relating to participation in the facilities, the Company agreed to pay its 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. Approximately $27.0 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 the Company's ratemaking policies. At December 31, 2006, the $7.2 million unamortized balance was comprised of $19.0 million related to the Company's share of original costs and additional investments, offset by $11.8 million of accumulated amortization.

The Company also participated with other electric utilities in the construction of the Phase I Hydro-Quebec ("Phase I") interconnection transmission facilities in northeastern Vermont, which were completed at a total cost of $140 million. Under a support agreement relating to participation in the facilities, the Company was obligated to pay its 4.55 percent share of Phase I capital costs over a 20-year recovery period that ended in 2006. The Company remains obligated to pay its share of operating and maintenance expenses through 2016. Under the terms of the support agreement, the Company can make an election in 2014 to extend its participation for an additional 20 years, through 2036. At December 31, 2006, the Company had recorded accumulated amortizations of $4.9 million representing its share of the original costs associated with the Phase I transmission facility.

Future annual payments relating to the Phase I and Phase II transmission facilities are expected to range from $2.7 million to $3.2 million from 2007 through 2015 and will decline thereafter. Approximately $0.6 million of the annual costs are reimbursed to the Company pursuant to the New England Power Pool Open Access Transmission Tariff.

For the year ended December 31, 2006, imputed interest on capital leases totaled $0.7 million. A summary of minimum lease payments as of December 31, 2006 follows (in thousands).

Year	Capital Leases
2007	$1,484
2008	1,413
2009	1,343
2010	1,273
2011	1,140
Thereafter	3,662
Future minimum lease payments	$10,315
Less: amount representing interest	2,830
Present value of net minimum lease payments	$7,485

Operating Leases: The Company leases its vehicles and related equipment under one operating lease agreement. The individual leases are mutually cancelable one year from lease inception. The Company has the ability to lease vehicles and related equipment up to an aggregate unamortized balance of $13.0 million, of which $6.6 million was outstanding at December 31, 2006 and $6.3 million at December 31, 2005.

Under the terms of the vehicle operating lease, the Company has 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, 2006, the Company would have been responsible for a maximum reimbursement of $5.7 million. The Company had a liability of $0.2 million at December 31, 2006 included in other current liabilities representing its obligation under the guarantee based on the fair market value of the entire portfolio, and this amount is offset by $0.2 million of prepayments.

From 1999 to 2002, SmartEnergy Water Heating Services, Inc. leased certain of the water heater tanks that it rents to customers under a master lease agreement. The lease terms are non-cancelable except in the general case of loss, destruction, unrepairable damage, customer termination or obsolescence. The lease is secured by essentially all of the assets of SmartEnergy Water Heating Services, Inc. and is guaranteed by Eversant. The Company's estimated maximum exposure under the master lease agreement is a potential payment due in the event of unrepairable damage, loss or destruction to the tanks of approximately $0.2 million. At December 31, 2006, the unamortized balance under this lease was $0.2 million.

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, 2006, future minimum rental payments required under non-cancelable leases are expected to total $0.4 million over the next five years, and annual minimum rental payments after that time are of a nominal amount.

Total rental expense, which includes pole attachment rents in addition to the operating lease agreements described above, amounted to $6.0 million in 2006, $5.5 million in 2005, and $5.2 million in 2004. These are included in Other operation on the Consolidated Statements of Income.

Catamount Indemnifications Under the terms of the agreements with Catamount and Diamond Castle, the Company 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 survive until June 30, 2007, except certain items that customarily survive indefinitely. Indemnification is subject to a $1.5 million deductible and a $15.0 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 survive beyond June 30, 2007. In the fourth quarter of 2005, the Company recorded a $0.3 million contingent liability related to one of Catamount's projects. This amount represents the Company's estimate of the fair value of the indemnification that is not subject to the deductible. The Company's estimated "maximum potential" amount of future payments related to these indemnifications is limited to $15.0 million. The Company has not recorded any liability related to these indemnifications.

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

Appropriated Retained Earnings Major hydro-electric 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. The Company's appropriated retained earnings included in retained earnings on the Consolidated Balance Sheets were $0.8 million at December 31, 2006 and $0.8 million at December 31, 2005.

NOTE 18 - SEGMENT REPORTING

The Company's reportable operating segments include: **Central Vermont Public Service Corporation ("CV - VT")**, 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; **Unregulated Companies** include Catamount Resources Corporation ("CRC"), Eversant Corporation, ("Eversant"), and CV Realty, Inc. CRC was formed to hold the Company's 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. CV 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 Note 1 - Business Organization and Summary of Significant accounting policies. Unregulated Companies are below the quantitative thresholds individually and in the aggregate; therefore, the Company has revised the table below to report all of its unregulated companies as an operating segment, including prior years. Inter-segment revenues are excluded from the table below and are less than $12,000 for each period. Financial information follows (in thousands):

2006	CV VT	Unregulated Companies	Reclassification and Consolidating Entries	Consolidated
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 expense	**8,569**	**284**	**(284)**	**8,569**
Equity in earnings of affiliates	**3,240**	**-**	**-**	**3,240**
Interest income (b)	**1,386**	**728**	**-**	**2,114**
Interest expense	**8,231**	**-**	**-**	**8,231**
Income from continuing operations	**17,074**	**1,027**	**-**	**18,101**
Investments in affiliates	**39,339**	**-**	**-**	**39,339**
Total assets	**499,125**	**2,314**	**(501)**	**500,938**
Construction and plant expenditures (c)	**23,810**	**208**	**-**	**24,018**
2005				
Revenues from external customers	$311,359	$1,847	$(1,847)	$311,359
Depreciation and amortizations (a)	13,300	174	(174)	13,300
Operating income tax (benefit) expense	(2,264)	304	(304)	(2,264)
Equity in earnings of affiliates	1,869	-	-	1,869
Interest income (b)	1,144	347	(249)	1,242
Interest expense	9,493	248	(248)	9,493
Income from continuing operations (d)	1,290	120	-	1,410
Investments in affiliates	15,801	-	-	15,801
Total assets	496,483	60,604	(5,654)	551,433
Construction and plant expenditures	17,558	-	-	17,558
2004				
Revenues from external customers	$302,286	$1,833	$(1,833)	$302,286
Depreciation and amortizations (a)	12,254	171	(171)	12,254
Operating income tax expense	834	340	(340)	834
Equity in earnings of affiliates	1,225	-	-	1,225
Interest income (b)	3,464	18	-	3,482
Interest expense	9,682	102	(102)	9,682
Income from continuing operations	7,071	422	-	7,493
Investments in affiliates	16,070	-	-	16,070
Total assets (e)	500,019	13,884	49,486	563,389
Construction and plant expenditures	20,174	-	-	20,174

(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) Includes $4.3 million for acquisition of utility property and $0.2 million included in other investing activities on the Consolidated Statement of Cash Flows.

(d) In 2005, included a $21.8 million per-tax charge. See Note 8 - Retail Rates and Regulatory Accounting.

(e) Reclassification and consolidating entries include $61.0 million of assets from discontinued operations related to the sale of Catamount. See Note 5 - Discontinued Operations.

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)
2006					
Operating revenues	$82,255	$78,992	$79,912	$84,579	$325,738
Operating income	$4,620	$2,238	$7,788	$6,677	$21,323
Income from continuing operations	$4,097	$995	$7,004	$6,005	$18,101
Income from discontinued operations	-	-	-	251	251
Net income	$4,097	$995	$7,004	$6,256	$18,352
Basic earnings per share - continuing operations	$0.33	$0.08	$0.67	$0.58	$1.65
Basic earnings per share - discontinued operations	-	-	-	0.02	0.02
Total basic earnings per share	$0.33	$0.08	$0.67	$0.60	$1.67
Diluted earnings per share - continuing operations	$0.32	$0.08	$0.66	$0.57	$1.64
Diluted earnings per share - discontinued operations	-	-	-	0.02	0.02
Total diluted earnings per share	$0.32	$0.08	$0.66	$0.59	$1.66
2005					
Operating revenues	$75,664	$75,116	$75,035	$85,544	$311,359
Operating income (loss)	$(988)	$3,657	$3,932	$1,967	$8,568
Income (loss) from continuing operations	$(4,915)	$2,634	$2,889	$802	$1,410
Income (loss) from discontinued operations	288	(544)	(168)	5,360	4,936
Net income	$(4,627)	$2,090	$2,721	$6,162	$6,346
Basic earnings (loss) per share - continuing operations	$(0.41)	$0.21	$0.22	$0.06	$0.09
Basic earnings (loss) per share - discontinued operations	0.02	(0.04)	(0.01)	0.43	0.40
Total basic earnings per share	$(0.39)	$0.17	$0.21	$0.49	$0.49
Diluted earnings (loss) per share - continuing operations	$(0.41)	$0.21	$0.22	$0.05	$0.08
Diluted earnings (loss) per share - discontinued operations	0.02	(0.04)	(0.01)	0.43	0.40
Total diluted earnings per share	$(0.39)	$0.17	$0.21	$0.48	$0.48

(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
Under the supervision and with participation of our management, including the Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act")), as of the end of the period covered by this annual report on Form 10-K. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2006, our disclosure controls and procedures were 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 the Company's Chief Executive Officer and Chief Financial Officer, and with participation of our 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 December 31, 2006.

Management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006 has been audited by Deloitte & Touche LLP, the independent registered public accounting firm that audited the Company's consolidated financial statements, whose report on Management's assessment and on the effectiveness of internal control over financial reporting is included below.

Changes in Internal Control over Financial Reporting
During 2006, the Company implemented and enhanced several internal controls over financial reporting to address the material weakness that existed at December 31, 2005, including:

(a) A formalized process for identifying and documenting the accounting, reporting and tax implications for new, non-routine and non-recurring transactions.
(b) A process for documenting existing balance sheet accounts and key triggering events that might require reclassification. The quarterly account reconciliation process was also enhanced for more timely reconciliations and review.
(c) A training plan within the Company's finance team with a focus on identifying potential differences between regulatory accounting requirements and generally accepted accounting principles ("GAAP"). The Company also incorporated various control checklists into its control processes, including a comprehensive GAAP checklist that was completed during the year end accounting and reporting process.

These internal controls were tested during 2006 and were found to be operating effectively as of December 31, 2006.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Stockholders of
Central Vermont Public Service Corporation

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Central Vermont Public Service Corporation and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, 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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, 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 as of and for the year ended December 31, 2006, of the Company and our report dated March 13, 2007 expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the adoption of a new accounting standard in 2006.

/s/ Deloitte & Touche LLP

Hartford, Connecticut
March 13, 2007

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 Proxy Statement of the Company for the 2007 Annual Meeting of Stockholders. The Executive Officers information is listed under Part I, Item 1. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 29, 2007.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the Proxy Statement of the Company for the 2007 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 29, 2007.

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 Proxy Statement of the Company for the 2007 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 29, 2007. 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	174,458	$14.50	-
1998 Stock Option Plan for Non-employee Directors	6,975	$19.18	-
2000 Stock Option Plan for Key Employees	190,680	$16.51	-
2002 Long-Term Incentive Plan	149,669	$20.59	95,669
Total	**521,782**	**$16.92**	**95,669**

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

The information required by this item is incorporated herein by reference to the Proxy Statement of the Company for the 2007 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 29, 2007.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the Proxy Statement of the Company for the 2007 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 29, 2007.

PART IV

		Filed Herewith at Page
Item 15.	Exhibits, Financial Statement Schedules.	
(a)1.	The following financial statements for Central Vermont Public Service Corporation and its wholly owned subsidiaries are filed as part of this report:	(See Item 8)

1.1 Consolidated Statement of Income for the three years ended December 31, 2006, 2005 and 2004

Consolidated Statement of Comprehensive Income for three the years ended December 31, 2006, 2005 and 2004

Consolidated Statement of Cash Flows for three the years ended December 31, 2006, 2005 and 2004

Consolidated Balance Sheet at December 31, 2006 and 2005

Consolidated Statement of Changes in Common Stock Equity at December 31, 2006, 2005 and 2004

Notes to Consolidated Financial Statements

(a)2. Financial Statement Schedules:

2.1 Central Vermont Public Service Corporation and its wholly owned subsidiaries:

Schedule II - Reserves for each of the three years ended December 31, 2006

Schedules not included have been omitted because they are not applicable or the required information is shown in the financial statements or notes thereto. Separate financial statements of the Registrant (which is primarily an operating company) have been omitted since they are consolidated only with those of totally held subsidiaries. Separate financial statements for certain subsidiary companies not consolidated will be filed separately in a Form 10-K/A.

(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 Bylaws

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 Mortgage dated October 1, 1929, between the Company and Old Colony Trust Company, Trustee, securing the Company's First Mortgage Bonds. (Exhibit B-3, File No. 2-2364)

4-2 Supplemental Indenture dated as of August 1, 1936. (Exhibit B-4, File No. 2-2364)

4-3 Supplemental Indenture dated as of November 15, 1943. (Exhibit B-3, File No. 2-5250)

4-4 Supplemental Indenture dated as of December 1, 1943. (Exhibit No. B-4, File No. 2-5250)

4-5 Directors' resolutions adopted December 14, 1943, establishing the Series C Bonds and dealing with other related matters. (Exhibit B-5, File No. 2-5250)

4-6 Supplemental Indenture dated as of April 1, 1944. (Exhibit No. B-6, File No. 2-5466)

4-7 Supplemental Indenture dated as of February 1, 1945. (Exhibit 7.6, File No. 2-5615) (22-385)

4-8 Directors' resolutions adopted April 9, 1945, establishing the Series D Bonds and dealing with other matters. (Exhibit 7.8, File No. 2-5615 (22-385)

4-9 Supplemental Indenture dated as of September 2, 1947. (Exhibit 7.9, File No. 2-7489)

4-10 Supplemental Indenture dated as of July 15, 1948, and directors' resolutions establishing the Series E Bonds and dealing with other matters. (Exhibit 7.10, File No. 2-8388)

4-11 Supplemental Indenture dated as of May 1, 1950, and directors' resolutions establishing the Series F Bonds and dealing with other matters. (Exhibit 7.11, File No. 2-8388)

4-12 Supplemental Indenture dated August 1, 1951, and directors' resolutions, establishing the Series G Bonds and dealing with other matters. (Exhibit 7.12, File No. 2-9073)

4-13 Supplemental Indenture dated May 1, 1952, and directors' resolutions, establishing the Series H Bonds and dealing with other matters. (Exhibit 4.3.13, File No. 2-9613)

4-14 Supplemental Indenture dated as of July 10, 1953. (July, 1953 Form 8-K, File No. 1-8222)

4-15 Supplemental Indenture dated as of June 1, 1954, and directors' resolutions establishing the Series K Bonds and dealing with other matters. (Exhibit 4.2.16, File No. 2-10959)

4-16 Supplemental Indenture dated as of February 1, 1957, and directors' resolutions establishing the Series L Bonds and dealing with other matters. (Exhibit 4.2.16, File No. 2-13321)

4-17 Supplemental Indenture dated as of March 15, 1960. (March, 1960 Form 8-K, File No. 1-8222)

4-18 Supplemental Indenture dated as of March 1, 1962. (March, 1962 Form 8-K, File No. 1-8222)

4-19 Supplemental Indenture dated as of March 2, 1964. (March, 1964 Form 8-K, File No, 1-8222)

4-20 Supplemental Indenture dated as of March 1, 1965, and directors' resolutions establishing the Series M Bonds and dealing with other matters. (April, 1965 Form 8-K, File No. 1-8222)

4-21 Supplemental Indenture dated as of December 1, 1966, and directors' resolutions establishing the Series N Bonds and dealing with other matters. (January, 1967 Form 8-K, File No. 1-8222)

4-22 Supplemental Indenture dated as of December 1, 1967, and directors' resolutions establishing the Series O Bonds and dealing with other matters. (December, 1967 Form 8-K, File No. 1-8222)

4-23 Supplemental Indenture dated as of July 1, 1969, and directors' resolutions establishing the Series P Bonds and dealing with other matters. (Exhibit B.23, July, 1969 Form 8-K, File No. 1-8222)

4-24 Supplemental Indenture dated as of December 1, 1969, and directors' resolutions establishing the Series Q Bonds January, and dealing with other matters. (Exhibit B.24, January, 1970 Form 8-K, File No. 1-8222)

4-25 Supplemental Indenture dated as of May 15, 1971, and directors' resolutions establishing the Series R Bonds and dealing with other matters. (Exhibit B.25, May, 1971, Form 8-K, File No. 1-8222)

4-26 Supplemental Indenture dated as of April 15, 1973, and directors' resolutions establishing the Series S Bonds and dealing with other matters. (Exhibit B.26, May, 1973, Form 8-K, File No. 1-8222)

4-27 Supplemental Indenture dated as of April 1, 1975, and directors' resolutions establishing the Series T Bonds and dealing with other matters. (Exhibit B.27, April, 1975, Form 8-K, File No. 1-8222)

4-28 Supplemental Indenture dated as of April 1, 1977. (Exhibit 2.42, File No. 2-58621)

4-29 Supplemental Indenture dated as of July 29, 1977, and directors' resolutions establishing the Series U, V, W, and X Bonds and dealing with other matters. (Exhibit 2.43, File No. 2-58621)

4-30 Thirtieth Supplemental Indenture dated as of September 15, 1978, and directors' resolutions establishing the Series Y Bonds and dealing with other matters. (Exhibit B-30, 1980 Form 10-K, File No. 1-8222)

4-31 Thirty-first Supplemental Indenture dated as of September 1, 1979, and directors' resolutions establishing the Series Z Bonds and dealing with other matters. (Exhibit B-31, 1980 Form 10-K, File No. 1-8222)

4-32 Thirty-second Supplemental Indenture dated as of June 1, 1981, and directors' resolutions establishing the Series AA Bonds and dealing with other matters. (Exhibit B-32, 1981 Form 10-K, File No. 1-8222)

4-45 Thirty-third Supplemental Indenture dated as of August 15, 1983, and directors' resolutions establishing the Series BB Bonds and dealing with other matters. (Exhibit B-45, 1983 Form 10-K, File No. 1-8222)

4-46 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)

4-47 Thirty-Fourth Supplemental Indenture dated as of January 15, 1985, and directors' resolutions establishing the Series CC Bonds and Series DD Bonds and matters connected therewith. (Exhibit B-47, 1985 Form 10-K, File No. 1-8222)

4-48 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)

4-49 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)

4-50 Thirty-Fifth Supplemental Indenture dated as of December 15, 1989 and directors' resolutions establishing the Series EE, Series FF and Series GG Bonds and matters connected therewith. (Exhibit 4-50, 1989 Form 10-K, File No. 1-8222)

4-51 Thirty-Sixth Supplemental Indenture dated as of December 10, 1990 and directors' resolutions establishing the Series HH Bonds and matters connected therewith. (Exhibit 4-51, 1990 Form 10-K, File No. 1-8222)

4-52 Thirty-Seventh Supplemental Indenture dated December 10, 1991 and directors' resolutions establishing the Series JJ Bonds and matters connected therewith. (Exhibit 4-52, 1991 Form 10-K, File No. 1-8222)

4-53 Thirty-Eight Supplemental Indenture dated December 10, 1993 establishing Series KK, LL, MM, NN, OO. (Exhibit 4-53, 1993 Form 10-K, File No. 1-8222)

4-54 Thirty-Ninth Supplemental Indenture Dated December 29, 1997. (Exhibit 4-54, 1997 Form 10-K, File No. 1-8222)

4-55 Fortieth Supplemental Indenture Dated January 28, 1998. (Exhibit 4-55, 1997 Form 10-K, File No. 1-8222)

4-56 Credit Agreement Dated As of November 5, 1997 among Central Vermont Public Service Corporation, The Lenders Named Herein and Toronto-Dominion (Texas), Inc., as Agent. (Exhibit 10.83, 1997 Form 10-K, File No. 1-8222)

4-56.1 First Amendment to Credit Agreement Dated as of April 15, 1998 (Exhibit 10.83.1, Form 10-Q, June 30, 1998, File No. 1-8222)

4-56.2 Second Amendment to Credit Agreement Dated as of June 2, 1998 (Exhibit 10.83.2, 1997 Form 10-Q, June 30, 1998, File No. 1-8222)

4-56-.3 Third Amendment to Credit Agreement Dated as of October 5, 1998 (Exhibit 4-56.3, 1998 Form 10-K, File No. 1-8222)

4-56.4 Open-End Mortgage, Security Agreement, Assignment of Rents and Leases, Fixture Filing, and Financing Statement Dated as of October 5, 1998 between the Company, as Mortgagor, in Favor of Toronto Dominion (Texas), Inc. as Collateral Agent for the Secured Parties (Exhibit 4-56.4, 1998 Form 10-K, File No. 1-8222)

Fourth Amendment to Credit Agreement, dated as of May 25, 1999 (Exhibit 4-56.4, Form 10-Q, June 30, 1999, File No. 1-8222)

4-56.5 Security Agreement, dated as of October 5, 1998, between the Company and Toronto Dominion (Texas), Inc. (Exhibit 4-56.5, 1998 Form 10-K, File No. 1-8222)

4-57 Forty-First Supplemental Indenture, dated as of July 19, 1999 and resolutions establishing Series PP (Millstone) Bonds, Series QQ (Seabrook) Bonds and Series RR (East Barnet) Bonds And matters connected therewith adopted July 19, 1999. (Exhibit 4-57, Form 10-Q, September 30, 1999, File No. 1-8222)

4-58 Second Mortgage Indenture, dated as of July 15, 1999, Central Vermont Public Service Corporation to the Bank of New York, Trustee (Exhibit 4-58, Form 10-Q, September 30, 1999, File No. 1-8222)

4-59 First Supplemental Indenture to the Second Mortgage, Central Vermont Public Service Corporation to the Bank of New York, Trustee, dated as of July 15, 1999, creating an issue of Mortgage Bonds, 8-1/8 percent Second Mortgage Bonds due 2004 (Exhibit 4-59, Form 10-Q, September 30, 1999, File No. 1-8222)

4-60 A/B Exchange Registration Rights Agreement, dated as of July 30, 1999 by and among Central Vermont Public Service Corporation and Donaldson, Lufkin & Jenrette Securities Corporation, TD Securities (USA) Inc. (Exhibit 4-60, Form 10-Q, September 30, 1999, File No. 1-8222)

4-61 Forty-Second Supplemental Indenture, dated as of June 11, 2001 and resolutions connected therewith adopted June 11, 2001. (Exhibit 4-61, Form 8-K, June 28,2001, File No. 1-8222)

4-62 Forty-Third Supplemental Indenture, dated as of April 1, 2003 and resolutions connected therewith adopted February 24, 2003. (Exhibit 4-62, Form 10-Q, June 30, 2003, File No. 1-8222)

4-63 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)

4-64 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)

4-65 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)

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, 1961, 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 Superseding Three Party Power Agreement dated January 1, 1990. (Exhibit 10-201, 1990 Form 10-K, File No. 1-8222)

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

* 10.4.3 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.

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)

10.6 Copy of agreement dated July 16, 1966, and letter supplement dated July 16, 1966, between Velco and Public Service Company of New Hampshire relating to purchase of single unit power from Merrimack II. (Exhibit C-9, File No. 2-26485)

10.6.1 Copy of Letter Agreement dated July 10, 1968, modifying Exhibit A. (Exhibit C-10, File No. 2-32917)

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 Agreement dated January 17, 1968, between Velco and Public Service Company of New Hampshire relating to purchase of additional unit power from Merrimack II. (Exhibit C-16, File No. 2-32917)

10.12 Copy of Agreement dated February 10, 1968 between the Company and Velco relating to purchase by Company of Merrimack II unit power. (There are 25 similar agreements between Velco and other utilities.) (Exhibit C-17, File No. 2-32917)

10.13 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)

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

10.14 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)

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

* 10.14.2 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.

10.15 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)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

10.16.27 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)

10.16.28 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)

10.17 Agreement dated October 13, 1972, for Joint Ownership, Construction and Operation of Pilgrim Unit No. 2 among Boston Edison Company and other utilities, including the Company. (Exhibit C-23, File No. 2-45990)

10.17.1 Amendments dated September 20, 1973, and September 15, 1974. (Exhibit C-24, File No. 2-51999)

10.17.2 Amendment dated December 1, 1974. (Exhibit C-25, File No. 2-54449)

10.17.3 Amendment dated February 15, 1975. (Exhibit C-26, File No. 2-53819)

10.17.4 Amendment dated April 30, 1975. (Exhibit C-27, File No. 2-53819)

10.17.5 Amendment dated as of June 30, 1975. (Exhibit C-28, File No. 2-54449)

10.17.6 Instrument of Transfer dated as of October 1, 1974, assigning partial interest from the Company to Green Mountain Power Corporation. (Exhibit C-29, File No. 2-52177)

10.17.7 Instrument of Transfer dated as of January 17, 1975, assigning a partial interest from the Company to the Burlington Electric Department. (Exhibit C-30, File No. 2-55458)

10.17.8 Addendum dated as of October 1, 1974 by which Green Mountain Power Corporation became a party thereto. (Exhibit C-31, File No. 2-52177)

10.17.9 Addendum dated as of January 17, 1975 by which the Burlington Electric Department became a party thereto. (Exhibit C-32, File No. 2-55450)

10.17.10 Amendment 23 dated as of 1975. (Exhibit C-50, 1975 Form 10-K, File No. 1-8222)

10.18 Agreement for Sharing Costs Associated with Pilgrim Unit No.2 Transmission dated October 13, 1972, among Boston Edison Company and other utilities including the Company. (Exhibit C-33, File No. 2-45990)

10.18.1 Addendum dated as of October 1, 1974, by which Green Mountain Power Corporation became a party thereto. (Exhibit C-34, File No. 2-52177)

10.18.2 Addendum dated as of January 17, 1975, by which Burlington Electric Department became a party thereto. (Exhibit C-35, File No. 2-55458)

10.19 Agreement dated as of May 1, 1973, for Joint Ownership, Construction and Operation of New Hampshire Nuclear Units among Public Service Company of New Hampshire and other utilities, including Velco. (Exhibit C-36, File No. 2-48966)

10.19.1 Amendments dated May 24, 1974, June 21, 1974, September 25, 1974, October 25, 1974, and January 31, 1975. (Exhibit C-37, File No. 2-53674)

10.19.2 Instrument of Transfer dated September 27, 1974, assigning partial interest from Velco to the Company. (Exhibit C-38, File No. 2-52177)

10.19.3 Amendments dated May 24, 1974, June 21, 1974, and September 25, 1974. (Exhibit C-81, File No. 2-51999)

10.19.4 Amendments dated October 25, 1974 and January 31, 1975. (Exhibit C-82, File No. 2-54646)

10.19.5 Sixth Amendment dated as of April 18, 1979. (Exhibit C-83, File No. 2-64294)

10.19.6 Seventh Amendment dated as of April 18, 1979. (Exhibit C-84, File No. 2-64294)

10.19.7 Eighth Amendment dated as of April 25, 1979. (Exhibit C-85, File No. 2-64815)

10.19.8 Ninth Amendment dated as of June 8, 1979. (Exhibit C-86, File No. 2-64815)

10.19.9 Tenth Amendment dated as of October 10, 1979. (Exhibit C-87, File No. 2-66334)

10.19.10 Eleventh Amendment dated as of December 15, 1979. (Exhibit C-88, File No.2-66492)

10.19.11 Twelfth Amendment dated as of June 16, 1980. (Exhibit C-89, File No. 2-68168)

10.19.12 Thirteenth Amendment dated as of December 31, 1980. (Exhibit C-90, File No. 2-70579)

10.19.13 Fourteenth Amendment dated as of June 1, 1982. (Exhibit C-104, 1982 Form 10-K, File No. 1-8222)

10.19.14 Fifteenth Amendment dated April 27, 1984. (Exhibit 10-134, 1986 Form 10-K, File No. 1-8222)

10.19.15 Sixteenth Amendment dated June 15, 1984. (Exhibit 10-135, 1986 Form 10-K, File No. 1-8222)

10.19.16 Seventeenth Amendment dated March 8, 1985. (Exhibit 10-136, 1986 Form 10-K, File No. 1-8222)

10.19.17 Eighteenth Amendment dated March 14, 1986. (Exhibit 10-137, 1986 Form 10-K, File No. 1-8222)

10.19.18 Nineteenth Amendment dated May 1, 1986. (Exhibit 10-138, 1986 Form 10-K, File No. 1-8222)

10.19.19 Twentieth Amendment dated September 19, 1986. (Exhibit 10-139, 1986 Form 10-K, File No. 1-8222)

10.19.20 Amendment No. 22 dated January 13, 1989. (Exhibit 10-193, 1989 Form 10-K, File No. 1-8222)

10.20 Transmission Support Agreement dated as of May 1, 1973, among Public Service Company of New Hampshire and other utilities, including Velco, with respect to New Hampshire Nuclear Units. (Exhibit C-39, File No. 2-48966)

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

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

10.21.2 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)

10.21.3 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)

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

10.22 Preliminary Agreement dated as of July 5, 1974, with respect to 1981 Montague Nuclear Generating Units. (Exhibit C-44, File No. 2-51733)

10.22.1 Amendment dated June 30, 1975. (Exhibit C-45, File No. 2-54449)

10.23 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)

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

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

10.24 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)

10.25 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)

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

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

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

10.25.4 Amendment dated July 1, 1989. (Exhibit 10-197, 1989 Form 10-K, File No. 1-8222)

10.25.5 Amendment dated February 1, 1992 (Exhibit 10.25.5, 1992 Form 10-K, File No. 1-8222)

10.25.6 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)

10.25.7 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)

10.25.8 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)

10.25.9 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)

10.25.10 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)

10.26 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)

10.27 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)

10.27.1 Supplementary Power Contract dated March 1, 1978. (Exhibit C-94, 1982 Form 10-K, File No. 1-8222)

10.27.2 Amendment dated August 22, 1980. (Exhibit C-95, 1982 Form 10-K, File No. 1-8222)

10.27.3 Amendment dated October 15, 1982. (Exhibit C-96, 1982 Form 10-K, File No. 1-8222)

10.27.4 Second Supplementary Power Contract dated April 30, 1984. (Exhibit C-115, 1984 Form 10-K, File No. 1-8222)

10.27.5 Additional Power Contract dated April 30, 1984. (Exhibit C-116, 1984 Form 10-K, File No. 1-8222)

10.27.6 1987 Supplementary Power Contract, dated as of April 1, 1987. (Exhibit 10.27.6, Form 10-Q, June 30, 2000, File No. 1-8222)

10.27.7 1996 Amendatory Agreement, dated December 1, 1996. (Exhibit 10.27.7, Form 10-Q, June 30, 2000, File No. 1-8222)

10.27.8 2000 Amendatory Agreement, dated May, 2000. (Exhibit 10.27.8, Form 10-Q, June 30, 2000, File No. 1-8222)

10.28 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)

10.29 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)

10.29.1 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)

10.30 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)

10.31 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)

10.32 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)

10.33 Form of Guarantee Agreement dated as of November 5, 1981, between Bankers Trust Company, as Trustee of the Vernon Energy Trust, and the Company, relating to Vermont Yankee Nuclear Fuel Sale Agreement. (Exhibit C-71, 1981 Form 10-K, File No. 1-8222)

10.34 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)

10.34.1 Amendment dated June 1, 1982. (Exhibit C-98, 1982 Form 10-K, File No. 1-8222)

10.35 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)

10.35.1 Amendment No. 1 dated January 1, 1986. (Exhibit C-132, 1986 Form 10-K, File No. 1-8222)

10.36 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)

10.37 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)

10.37.1 Amendment No. 3 dated January 1, 1986. (Exhibit 10-149, 1986 Form 10-K, File No. 1-8222)

10.38 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)

10.39 Power Purchase Agreement between Velco and CVPS dated June 1, 1981. (Exhibit C-103, 1982 Form 10-K, File No. 1-8222)

10.40 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)

10.40.1 Amendment No. 1 dated October 5, 1982. (Exhibit C-108, 1983 Form 10-K, File No. 1-8222)

10.40.2 Amendment No. 2 dated December 30, 1983. (Exhibit C-109, 1983 Form 10-K, File No. 1-8222)

10.40.3 Amendment No. 3 dated January 10, 1984. (Exhibit 10-143, 1986 Form 10-K, File No. 1-8222)

10.41 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)

10.42 Copy of Highgate Transmission Interconnection Preliminary Support Agreement dated April 9, 1984. (Exhibit C-117, 1984 Form 10-K, File No. 1-8222)

10.43 Copy of Allocation Contract for Hydro-Quebec Firm Power dated July 25, 1984. (Exhibit C-118, 1984 Form 10-K, File No. 1-8222)

10.43.1 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)

10.44 Copy of Highgate Operating and Management Agreement dated August 1, 1984. (Exhibit C-119, 1986 Form 10-K, File No. 1-8222)

10.44.1 Amendment No. 1 dated April 1, 1985. (Exhibit 10-152, 1986 Form 10-K, File No. 1-8222)

10.44.2 Amendment No. 2 dated November 13, 1986. (Exhibit 10-167, 1987 Form 10-K, File No. 1-8222)

10.44.3 Amendment No. 3 dated January 1, 1987. (Exhibit 10-168, 1987 Form 10-K, File No. 1-8222)

10.45 Copy of Highgate Construction Agreement dated August 1, 1984. (Exhibit C-120, 1984 Form 10-K, File No. 1-8222)

10.45.1 Amendment No. 1 dated April 1, 1985. (Exhibit 10-151, 1986 Form 10-K, File No. 1-8222)

10.46 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)

10.46.1 Amendment No. 1 dated April 1, 1985. (Exhibit 10-153, 1986 Form 10-K, File No. 1-8222)

10.46.2 Amendment No. 2 dated April 18, 1985. (Exhibit 10-154, 1986 Form 10-K, File No. 1-8222)

10.46.3 Amendment No. 3 dated February 12, 1986. (Exhibit 10-155, 1986 Form 10-K, File No. 1-8222)

10.46.4 Amendment No. 4 dated November 13, 1986. (Exhibit 10-169, 1987 Form 10-K, File No. 1-8222)

10.46.5 Amendment No. 5 and Restatement of Agreement dated January 1, 1987. (Exhibit 10-170, 1987 Form 10-K, File No. 1-8222)

10.47 Copy of the Highgate Transmission Agreement dated August 1, 1984. (Exhibit C-122, 1984 Form 10-K, File No. 1-8222)

10.48 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)

10.48.1 First Amendment dated March 1, 1985. (Exhibit C-127, 1985 Form 10-K, File No. 1-8222)

10.49 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)

10.50 Service Contract Agreement between the Company and the State of Vermont for distribution and sale of energy from St. Lawrence power projects ("NYPA Power") dated as of June 25, 1985. (Exhibit C-130, 1985 Form 10-K, File No. 1-8222)

10.50.1 Lease and Operating Agreement between the Company and the State of Vermont dated as of June 25, 1985. (Exhibit C-131, 1985 Form 10-K, File No. 1-8222)

10.51 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)

10.54 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)

10.55 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)

10.55.1 Amendment dated February 1, 1987. (Exhibit 10-171, 1987 Form 10-K, File No. 1-8222)

10.56 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)

10.56.1 Amendment No. 1 dated September 28, 1988. (Exhibit 10-182, 1988 Form 10-K, File No. 1-8222)

10.56.2 Amendment No. 2 dated October 1, 1991. (Exhibit 10.56.2, 1991 Form 10-K, File No. 1-8222)

10.56.3 Amendment No. 3 dated December 31, 1994. (Exhibit 10.56.3, 1994 Form 10-K, File No. 1-8222)

10.56.4 Amendment No. 4 dated December 31, 1996. (Exhibit 10.56.4, 1996 Form 10-K, file No. 1-8222)

10.57 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)

10.57.1 Amendment No. 1 dated September 22, 1985. (Exhibit 10-157, 1986 Form 10-K, File No. 1-8222)

10.58 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)

10.58.1 Amendment No. 1 dated June 20, 1986. (Exhibit 10-159, 1986 Form 10-K, File No. 1-8222)

10.59 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)

10.59.1 Amendment No. 17 dated November 25, 1985. (Exhibit 10-162, 1986 Form 10-K, File No. 1-8222)

10.62 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)

10.63 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)

10.63.1 Amendment dated September 1, 1993 (Exhibit 10.63.1, 1993 Form 10-K, File No. 1-8222)

10.64 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)

10.64.1 Amendment No. 1 dated August 31, 1988. (Exhibit 10-191, 1988 Form 10-K, File No. 1-8222)

10.64.2 Amendment No. 2 dated September 19, 1990. (Exhibit 10-202, 1990 Form 10-K, File No. 1-8222)

10.64.3 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)

10.64.4 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)

10.66 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)

10.66.1 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)

10.67 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)

10.75 Receivables Purchase Agreement between Central Vermont Public Service Corporation, Central Vermont Public Service Corporation as Service Agent and The First National Bank of Boston dated November 29, 1988. (Exhibit 10-192, 1988 Form 10-K)

10.75.1 Agreement Amendment No. 1 dated December 21, 1988 Exhibit 10.75.1, 1993 Form 10-K, File No. 1-8222)

10.75.2 Letter Agreement dated December 4, 1989 (Exhibit 10.75.2, 1993 Form 10-K, File No. 1-8222)

10.75.3 Agreement Amendment No. 2 dated November 29, 1990 (Exhibit 10.75.3, 1993 Form 10-K, File No. 1-8222)

10.75.4 Agreement Amendment No. 3 dated November 29, 1991 (Exhibit 10.75.4, 1993 Form 10-K, File No. 1-8222)

10.75.5 Agreement Amendment No. 4 dated November 29, 1992 (Exhibit 10.75.5, 1993 Form 10-K, File No. 1-8222)

10.75.6 Agreement Amendment No. 5 dated November 29, 1993 (Exhibit 10.75.6, 1997 Form 10-K, File No. 1-8222)

10.75.7 Agreement Amendment No. 6 dated November 29, 1994 (Exhibit 10.75.7, 1997 Form 10-K, File No. 1-8222)

10.75.8 Agreement Amendment No. 7 dated November 29, 1995 (Exhibit 10.75.8, 1997 Form 10-K, File No. 1-8222)

10.75.9 Agreement Amendment No. 8 dated February 5, 1997 (Exhibit 10.75.9, 1997 Form 10-K, File No. 1-8222)

10.75.10 Agreement Amendment No. 9 dated February 2, 1998 (Exhibit 10.75.10, 1997 Form 10-K, File No. 1-8222)

10.83 Credit Agreement Dated As of November 5, 1997, see exhibit 4-56; 10.83.1 and 10.83.2, see exhibit 4-56.1 and 4-56.2.

10.84 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)

10.85 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)

10.86 Purchase and Sale Agreement by and between Public Service Company of New Hampshire and Central Vermont Public Service Corporation/Connecticut Valley Electric Company Inc. dated January 31, 2003. (Exhibit 10-86, Form 10-Q, March 31, 2003, File No. 1-8222)

10.87 Settlement Agreement by and between Connecticut Valley Electric Company Inc. Central Vermont Public Service Corporation The Governor's Office of Energy and Community Services The Staff of the New Hampshire Public Utilities Commission Office of Consumer Advocate The City of Claremont, New Hampshire New Hampshire Legal Assistance dated January 31, 2003. (Exhibit 10-87, Form 10-Q, March 31, 2003, File No. 1-8222)

10.88 Agreement between Central Vermont Public Service Corporation and Local Union No. 300 International Brotherhood of Electrical Workers Effective as of January 1, 2005. (Exhibit 10.88, Current Report on Form 8-K Filed January 5, 2005, File No. 1-8222)

10.89 Financing Agreement among Catamount Sweetwater Holdings LLC; UFJ Bank Limited; Bayerische Landesbank; and The Lenders Parties Hereto dated as of July 12, 2005. (Catamount Sweetwater Holdings LLC is a wholly owned subsidiary of Catamount Energy Corporation. Catamount Energy Corporation is a wholly owned subsidiary of Catamount Resources Corporation. Catamount Resources Corporation is a wholly owned subsidiary of Central Vermont Public Service Corporation. (Exhibit 10.89, Current Report on Form 8-K Filed July 15, 2005, File No. 1-8222)

10.90 Stock Subscription Agreement by and among CEC Wind Acquisition, LLC, Catamount Energy Corporation, Catamount Resources Corporation, and Central Vermont Public Service Corporation, dated October 12, 2005. (Exhibit 10.90, Current Report on Form 8-K Filed October 18, 2005, File No. 1-8222)

10.90.1 Form of the Amended and Restated Certificate of Incorporation. (Exhibit 10.90.1, Current Report on Form 8-K Filed October 18, 2005, File No. 1-8222)

10.90.2 Stockholders' Agreement among Catamount Energy Corporation and the stockholders parties thereto, dated October 12, 2005. (Exhibit 10.90.2, Current Report on Form 8-K Filed October 18, 2005, File No. 1-8222)

10.90.3 Registration Rights Agreement among Catamount Energy Corporation and the stockholders parties thereto, dated October 12, 2005. (Exhibit 10.90.3, Current Report on Form 8-K Filed October 18, 2005, File No. 1-8222)

10.90.4 Put Option Purchase and Sale Agreement between Central Vermont Public Service Corporation and CEC Wind Acquisition, LLC, dated October 12, 2005. (Exhibit 10.90.4, Current Report on Form 8-K Filed October 18, 2005, File No. 1-8222)

10.90.5 Exercise of Put Option Notice. (Exhibit 10.90.5, Current Report on Form 8-K Filed November 21, 2005, File No. 1-8222)

10.91 Credit Agreement dated as of October 21, 2005 between Central Vermont Public Service Corporation as Borrower and JPMorgan Chase Bank, N.A. as Lender. (Exhibit 10.91, Current Report on Form 8-K Filed November 1, 2005, File No. 1-8222)

10.92 Voting Agreement and Irrevocable Proxy between Central Vermont Public Service Corporation and Mr. Jerry Zucker. (Exhibit 10.92, Current Report on Form 8-K Filed March 16, 2006, File No. 1-8222)

10.93 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)

10.93.1 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)

* 10.94 Operating Agreement of Vermont Transco, LLC effective July 1, 2006.

* 10.95 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.

EXECUTIVE COMPENSATION PLANS AND ARRANGEMENTS

A 10.68 Stock Option Plan for Non-Employee Directors dated July 18, 1988. (Exhibit 10-184, 1988 Form 10-K, File No. 1-8222)

A 10.69 Stock Option Plan for Key Employees dated July 18, 1988. (Exhibit 10-185, 1988 Form 10-K, File No. 1-8222)

A 10.70 Officers Supplemental Insurance Plan authorized July 9, 1984. (Exhibit 10-186, 1988 Form 10-K, File No. 1-8222)

A 10.71 Officers Supplemental Deferred Compensation Plan dated November 4, 1985. (Exhibit 10-187, 1988 Form 10-K, File No. 1-8222)

A 10.71.1 Amendment dated October 2, 1995. (Exhibit 10.71.1, 1995 Form 10-K, File No. 1-8222)

A 10.72 Directors' Supplemental Deferred Compensation Plan dated November 4, 1985. (Exhibit 10-188, 1988 Form 10-K, File No. 1-8222)

A 10.72.1 Amendment dated October 2, 1995. (Exhibit 10.72.1, 1995 Form 10-K, File No. 1-8222)

A 10.73 Management Incentive Compensation Plan as adopted September 9, 1985. (Exhibit 10-189, 1988 Form 10-K, File No. 1-8222)

A 10.73.1 Revised Management Incentive Plan as adopted February 5, 1990. (Exhibit 10-200, 1989 Form 10-K, File No. 1-8222)

A 10.73.2 Revised Management Incentive Plan dated May 2, 1995. (Exhibit 10.73.2, 1995 Form 10-K, File No. 1-8222)

A 10.74 Officers' Change of Control Agreements as approved October 3, 1988. (Exhibit 10-190, 1988 Form 10-K, File No. 1-8222)

A 10.78 Stock Option Plan for Non-Employee Directors dated April 30, 1993 (Exhibit 10.78, 1993 Form 10-K, File No. 1-8222)

A 10.79 Officers Insurance Plan dated November 15, 1993 (Exhibit 10.79, 1993 Form 10-K, File No. 1-8222)

A 10.79.1 Amendment dated October 2, 1995. (Exhibit No. 10.79.1, 1995 Form 10-K, File No. 1-8222)

A 10.80 Directors' Supplemental Deferred Compensation Plan dated January 1, 1990 (Exhibit 10.80, 1993 Form 10-K, File No. 1-8222)

A 10.80.1 Amendment dated October 2, 1995. (Exhibit No. 10.80.1, 1995 Form 10-K, File No. 1-8222)

A 10.81 Officers' Supplemental Deferred Compensation Plan dated January 1, 1990 (Exhibit 10.81, 1993 Form 10-K, File No. 1-8222)

A 10.82 Management Incentive Plan for Executive Officers dated January 1, 1997. (Exhibit 10.82, 1996 Form 10-K, File No. 1-8222)

A 10.83 Management Incentive Plan for Executive Officers dated January 1, 1998 (Exhibit A10.83, Form 10-Q, March 31, 1998, File No. 1-8222)

A 10.84 Officers' Change of Control Agreement dated January 1, 1998 (Exhibit 10.84, 1998 Form 10-K, File No. 1-8222)

A 10.85 Officers' Supplemental Retirement and Deferred Compensation Plan as Amended and Restated Effective January 1, 1998 (Exhibit 10.85, 1998 Form 10-K, File No. 1-8222)

A 10.85.1 Officers' Supplemental Retirement and Deferred Compensation Plan, Amended and Restated Effective January 1, 2005. (Exhibit A 10.85.1, 2004 Form 10-K, File No. 1-8222)

A 10.86 1993 Stock Option Plan for Non-employee Directors (Exhibit 28 to Registration Statement, Registration 33-62100)

A 10.87 1997 Stock Option Plan for Key Employees (Exhibit 4.3 to Registration Statement, Registration 333-57001)

A 10.88 1997 Restricted Stock Plan for Non-employee Directors and Key Employees (Exhibit 4.3 to Registration Statement, Registration 333-57005)

A 10.89 Management Incentive Plan for Executive Officers dated January 1, 1999. (Exhibit A10.89, Form 10-Q, March 31, 1999, File No. 1-8222)

A 10.90 Performance Share Incentive Plan dated effective January 1, 1999. (Exhibit A10.90, Form 10-Q, June 30, 1999, File No. 1-8222)

A 10.91 Management Incentive Plan for Executive Officers dated January 1, 2000. (Exhibit A10.91, Form 10-Q, March 31, 2000, File No. 1-8222)

A 10.92 Officers' Change of Control Agreements as approved April 3, 2000. (Exhibit A10.92, Form 10-Q, March 31, 2000, File No. 1-8222)

A 10.93 Management Incentive Plan for Executive Officers dated January 1, 2001. (Exhibit A10.93, Form 10-Q, March 31, 2001, File No. 1-8222)

A 10.94 Termination Agreement between the Company and Craig A. Parenzan. (Exhibit A10.94, Form 10-Q, March 31, 2001, File No. 1-8222)

A 10.95 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) Necessary?

A 10.96 Form of Deferred Compensation Plan for Officers and Directors. (Exhibit A10.96, Form 10-Q, March 31, 2002, File No. 1-8222)

A 10.96.1 Deferred Compensation Plan for Officers and Directors of Central Vermont Public Service Corporation, Amended and Restated Effective January 1, 2005. (Exhibit A10.96.1, 2004 Form 10-K, File No. 1-8222)

A 10.97 Management Incentive Plan for Executive Officers dated January 1, 2002. (Exhibit A10.97, Form 10-Q, March 31, 2002, File No. 1-8222)

A 10.97.1 Management Incentive Plan, Effective as of January 1, 2005. (Exhibit A10.97.1, 2004 Form 10-K, File No. 1-8222)

A 10.97.2 Management Incentive Plan, Effective as of January 1, 2006.

* A 10.97.3 Management Incentive Plan, Effective as of January 1, 2007.

A 10.98 Change-In-Control Agreement dated April 15, 2002 between the Company and Jean H. Gibson. (Exhibit A10.98, Form 10-Q, March 31, 2002, File No. 1-8222)

A 10.99 2002 Long-Term Incentive Plan. (Previously filed as Schedule A, Form DEF 14A - Proxy Statement, March 29, 2002, File No. 1-8222) - (Exhibit A 10.95, September 30, 2006 Form 10-Q, File No. 1-8222) Necessary?

A 10.100 Performance Share Incentive Plan dated effective January 1, 2004. (Exhibit A10.100, Form 10-Q, June 30, 2004, File No. 1-8222)

A 10.100.1 Performance Share Incentive Plan, Effective January 1, 2005. (Exhibit A10.100.1, 2004 Form 10-K, File No. 1-8222)

A 10.100.2 Performance Share Incentive Plan, Effective January 1, 2006.

* A 10.100.3 Performance Share Incentive Plan, Effective January 1, 2007.

A 10.101 Form of Central Vermont Public Service Performance Share Agreement Pursuant to the Performance Share Incentive Plan. (Exhibit A10.101, Form 10-Q, September 30, 2004, File No. 1-8222)

A 10.102 Form of Central Vermont Public Service Corporation Stock Option Agreement Pursuant to the 2002 Long-Term Incentive Plan. (Exhibit A10.102, Form 10-Q, September 30, 2004, File No. 1-8222)

A 10.103 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 A10.103, Form 10-Q, September 30, 2004, File No. 1-8222)

A 10.104 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 A10.104, Form 10-Q, September 30, 2004, File No. 1-8222)

A 10.105 Form of Indemnity Agreement between Directors and Executive Officers and Central Vermont Public Service Corporation. (Exhibit A10.105, 2004 Form 10-K, File No. 1-8222)

A 10.106 Change-In-Control Agreement dated as of November 17, 2003 between the Company and Dale A. Rocheleau. (Exhibit A10.106, 2004 Form 10-K, File No. 1-8222)

A 10.107 Catamount Energy Corporation 2002 Project Incentive Compensation Plan effective January 1, 2002. (Exhibit A10.107, 2004 Form 10-K, File No. 1-8222)

A 10.107.1 Amended and Restated Catamount Energy Corporation 2002 Project Incentive Compensation Plan. (Exhibit A 10.107.1, 2004 Form 10-K/A, File No. 1-8222)

A 10.108 Restricted Stock Award Agreement dated February 27, 2006 between the Company and Robert H. Young. (Exhibit A10.108, Current Report on Form 8-K filed March 3, 2006, 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

24 Power of Attorney

* 24.1 Power of Attorney executed by Directors and Officers of Company

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

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

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the consolidated financial statements of Central Vermont Public Service Corporation and subsidiaries (the "Company") as of December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, and the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, and have issued our reports thereon dated March 13, 2007 (our report on the consolidated financial statements expressed an unqualified opinion and included an explanatory paragraph regarding the adoption of a new accounting standard in 2006); such consolidated financial statements and reports are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedules of the Company listed in Item 15. These consolidated financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Hartford, Connecticut
March 13, 2007

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
2006					
Reserves deducted from assets to which they apply:					
			$106,373 (1) 762,154 (2)	$1,757,826 (5) 1,390,104 (9)	
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 (7)	$200,000			$200,000	$-
Environmental Reserve	$5,426,110			$3,349,828 (10)	$2,076,282
2005					
Reserves deducted from assets to which they apply:					
			$118,657(1) 479,489 (2) 433,169 (4)		
Reserve for uncollectible accounts receivable	$1,948,341	$1,048,860	$1,031,315	$1,414,379 (5)	$2,614,137
Reserve for uncollectible accounts receivable - affiliates	$-	$47,913			$47,913
Accumulated depreciation of non-utility property	$4,877,179	$27,821		$841,509	$4,063,491
Discontinued operations - Catamount	$762,923			$762,923	$-
Reserves shown separately:					
Injuries and damages reserve (7)	$225,580			$25,580	$200,000
Environmental Reserve	$6,064,654			$638,544 (8)	$5,426,110
2004					
Reserves deducted from assets to which they apply:					
			$153,959(1) 479,295 (2) 189,412 (3) 340,831 (4)	$2,248,648 (5) (50,703) (6)	
Reserve for uncollectible accounts receivable	$1,577,907	$1,404,882	$1,163,497	$2,197,945	$1,948,341
Accumulated depreciation of non-utility property	$4,412,778	$743,523		$279,122	$4,877,179
Discontinued operations - Catamount	$-	$580,676	$182,247		$762,923
Reserves shown separately:					
Injuries and damages reserve (7)	$225,580				$225,580
Environmental Reserve	$7,190,633			$1,125,979 (8)	$6,064,654

(1) Amount collected from collection agencies
(2) Collections of accounts previously written off
(3) Charged against revenue
(4) Reserve against rents
(5) Uncollectible accounts written off
(6) Amount related to Connecticut Valley discontinued operations
(7) This represents the Company's long-term reserve for injuries & damages needed to meet the Company's liability not covered by insurance. The Company is self-insured up to $200,000; therefore, any activity for the year is charged to expense and recorded to the current liability.
(8) Environmental remediation payments from reserve
(9) Settlement of accounts related to pole attachment tariff resolution
(10) Reduction of reserve based on updated cost estimates for remediation

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 15, 2007

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 15, 2007.

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
Frederic H. Bertrand*	Director
Janice B. Case*	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.