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, 2003

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	(802) 773-2711

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 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 an accelerated filer (as defined in Rule 12b-2 of the Act.) Yes___ No__X_

State the aggregate market value of the voting stock held by non-affiliates of the registrant: $286,210,205 based upon the closing price as of January 30, 2004 of Common Stock, $6 Par Value, on the New York Stock Exchange as reported in the Eastern Edition of the Wall Street Journal.

Indicate the number of shares outstanding of each of the registrant's classes of Common Stock: As of January 31, 2004, there were outstanding 12,050,956 shares of 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 4, 2004 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.

Cover page continued

TABLE OF CONTENTS

Item 1. Business

Central Vermont Public Service Corporation (the "Company") makes available free of charge through its Internet Web site, http://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 those reports are electronically filed with the Securities and Exchange Commission. Access to the reports is available from the main page of the Company's Internet Web site through "Investor Relations". The Company's Corporate Ethics and Conflict of Interest Policy and Corporate Governance Guidelines are also available on our Internet Web site. Access to these documents is available from the main page of the Company's Internet Web site through "Corporate Governance and Ethics". Printed copies of these documents are also available upon written request to the Assistant Corporate Secretary at our principal executive offices.

Overview

The Company, incorporated under the laws of Vermont on August 20, 1929, is engaged in the purchase, production, transmission, distribution and sale of electricity. The Company has various wholly and partially owned subsidiaries. These subsidiaries are described below.

The Company is the largest electric utility in Vermont and serves 148,164 customers in nearly three-quarters of the towns, villages and cities in Vermont. In addition, the Company supplies electricity to one municipal utility, one rural cooperative, and one private utility.

The Company's sales are derived from a diversified customer mix. The Company's sales to residential, commercial and industrial customers accounted for 76 percent of total mWh sales for 2003. Sales to the five largest retail customers receiving electric service from the Company during the same period aggregated about 5 percent of the Company's total electric revenues for the year. The Company's resale firm sales accounted for approximately 4 percent and other resale sales which include contract sales, sales to ISO-New England and short-term system capacity sales accounted for approximately 20 percent of total mWh sales for 2003.

The Company's wholly owned subsidiary, 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. It served 10,507 customers in 13 communities in New Hampshire. Connecticut Valley's sales were also derived from a diversified customer mix. Connecticut Valley's sales to residential, commercial and industrial customers accounted for 99.5 percent of total mWh sales for 2003. Sales to its five largest retail customers during the same period aggregated about 16 percent of Connecticut Valley's total electric revenues for 2003. 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 ("PSNH"). See New Hampshire Retail Rates below for additional information related to the sale.

The Company owns 50.5 percent of the common stock and 46.6 percent of the preferred stock of Vermont Electric Power Company, Inc. ("VELCO"). In the third quarter of 2003, the Company's ownership in VELCO changed from 50.6 percent to 50.5 percent as a result of other owners acquiring additional shares of VELCO's Class C common stock. VELCO owns the high voltage transmission system in Vermont. 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 58.85 percent of the common stock of Vermont Yankee Nuclear Power Corporation ("Vermont Yankee"). The Company's ownership percentage changed from 33.23 percent to 58.85 percent in the fourth quarter of 2003, related to the buy-back of shares held by minority owners. Vermont Yankee 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, Vermont Yankee completed the sale of its nuclear power plant to Entergy Nuclear Vermont Yankee, LLC ("Entergy"). Vermont Yankee administers the purchased power contracts among the former plant owners and Entergy. For additional information see discussion of Equity Ownership in Plants below.

The Company owns 2 percent of the outstanding common stock of Maine Yankee Atomic Power Company, 2 percent of the outstanding common stock of Connecticut Yankee Atomic Power Company and 3.5 percent of the outstanding common stock of Yankee Atomic Electric Company. For additional information see Nuclear Decommissioning Costs below.

The Company's wholly owned subsidiary, Catamount Resources Corporation, was formed for the purpose of holding the Company's subsidiaries that invest in unregulated business opportunities. One of its subsidiaries, Catamount Energy Corporation, invests through its wholly owned subsidiaries in non-regulated energy generation projects in the United States and the United Kingdom. Another of its subsidiaries, 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. See PART II Item 7, and Item 8, Notes 3 and 14, for additional information regarding the Company's diversification activities.

Other wholly owned subsidiaries of the Company include:

- 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.
- Custom Investment Corporation, which was formed for the purpose of holding passive investments, including the stock of the Company's subsidiaries that invest in regulated business opportunities.

REGULATION AND COMPETITION

State Commissions

The Company is subject to the regulatory authority of the Vermont Public Service Board ("PSB") with respect to rates, and the Company and VELCO are subject to PSB jurisdiction related to securities issues, construction of major generation and transmission facilities and various other matters. The Company is subject to the regulatory authority of the New Hampshire Public Utilities Commission ("NHPUC") as to matters pertaining to construction and transfers of utility property in New Hampshire. 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, a 619 MW generating plant and Millstone Unit #3, an 1159 MW nuclear generating facility, respectively.

Connecticut Valley is subject to the regulatory authority of the NHPUC with respect to rates, securities issues and various other matters. On January 1, 2004, Connecticut Valley completed the sale of substantially all of its plant assets and its franchise to PSNH. See discussion of Discontinued Operations below.

Federal Power Act

Certain phases of the businesses of the Company and VELCO, 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, and the Company and VELCO as interstate public utilities under Parts II and III of the Federal Power Act, as amended and supplemented by the National Energy Act. The Company has nine licenses that will expire in the future at various times under PART I of the Federal Power Act for twelve of its hydroelectric plants. Two additional projects have initial license applications pending. The Company has obtained an exemption from licensing for the Bradford and East Barnet projects.

Public Utility Holding Company Act of 1935

Although the Company, by reason of its ownership of a utility subsidiary, is a holding company, as defined in the Public Utility Holding Company Act of 1935, it is presently exempt, pursuant to Rule 2, promulgated by the Commission under said Act, from all the provisions of said Act except Section 9 (a)(2) thereof relating to the acquisition of securities of public utility affiliates.

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 which environmental regulation may ultimately have upon its existing and proposed facilities and operations. The Company believes that any such costs related to its utility operations would be recoverable through the ratemaking process. For additional information see Part II Item 8, Note 13, herein for disclosures relating to environmental contingencies, hazardous substance releases and the control measures related thereto.

Nuclear Matters

The nuclear generating facilities in which the Company has an interest are subject to extensive regulations by the Nuclear Regulatory Commission ("NRC"). The NRC is empowered to regulate the siting, construction and operation of nuclear reactors with respect to public health, safety, and environmental and antitrust matters. Under its continuing jurisdiction, the NRC may, after appropriate proceedings, require modification of units for which operating licenses have already been issued, or impose new conditions on such licenses, and may require that the operation of a unit cease or that the level of operation of a unit be temporarily or permanently reduced. See discussion of Nuclear Decommissioning Costs below.

Competition

Competition currently takes several forms. At the wholesale level, other electric power providers compete as suppliers to resale customers. Another competitive threat is the potential for customers to form municipally owned utilities in the Company's service territory. 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.

Pursuant to Vermont statutes (30 V.S.A. Section 249), the PSB has established as the service area for the Company the area it now serves. 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 the failure of the PSB 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 and approves certain findings. Those findings are (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, in the event the parties fail to reach an agreement, by the PSB after a hearing. 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. The Town of Springfield acted to acquire the Company's distribution facilities in that community pursuant to a vote in 1977. This action was subsequently discontinued between Springfield and the Company in 1985.

In 2002, the Town of Rockingham voted to pursue purchasing the Company's distribution facilities, Green Mountain Power's ("GMP") distribution facilities, and USGen's hydroelectric facility located in Bellows Falls. The Company and GMP refused to voluntarily sell their distribution facilities. In November of 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 on December 23, 2003, was able to obtain a permanent injunction from the Superior Court prohibiting Rockingham from pursuing this course of action. Should Rockingham decide to continue this action it must now proceed to the PSB under Title 30. The Company currently serves approximately 260 customers in Rockingham which customers consume approximately 2.024 megawatt hours annually.

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 electric sales. Competitive risks in these market segments are primarily related to seasonal, one-shift operations that can tolerate periodic power outages, and for industrial customers with steady heat loads where the generator's waste heat can be used in their manufacturing process. Competitive advantages for electricity in those segments are convenience, the cost of back-up power sources, space requirements, noise problems, air emission and siting permit issues, and maintenance requirements.

The electric utility industry is in a period of transition that in some cases has resulted in a shift away from ratemaking based on cost of service and return on equity to more market-based rates with energy sold to customers by competing retail energy service providers. Many states have implemented new mechanisms to bring greater competition, customer choice and market influence to the industry while retaining the public benefits associated with the current regulatory system. The State of Vermont is pursuing a variety of initiatives that are aimed at restructuring the provision of electric service without introducing retail choice. See PART II Item 7, herein, for a discussion of Electric Industry Restructuring, and Wholesale Rates below, for a discussion related to the Company's wholesale electric business.

RATE DEVELOPMENTS

Vermont Retail Rates

The Company recognizes that adequate and timely rate relief is required to maintain its financial strength, particularly since Vermont law does not allow power and fuel costs to be passed to consumers through fuel adjustment clauses. The Company will continue to review costs and request rate increases when warranted.

2000 Retail Rate Case: The Company's current retail rates are based on a June 26, 2001 PSB Order approving a settlement with the DPS, including a 3.95 percent rate increase effective July 1, 2001. As part of the settlement, the Company also agreed to a $9 million write-off ($5.3 million after-tax) of regulatory assets and a rate freeze through January 1, 2003. The order also ended uncertainty over Hydro-Quebec cost recovery by providing full cost recovery, made the January 1, 1999 temporary rates permanent, allowed the Vermont utility a return on common equity of 11 percent for the year ending June 30, 2002 (capped through January 1, 2004), and created new service quality standards. Lastly, the rate order requires the Company to return up to $16 million to ratepayers if there is a merger, acquisition or asset sale that requires PSB approval.

July 2003 Memorandum of Understanding ("MOU"): In April 2003, the Company prepared cost of service studies for rate years 2003 and 2004, in accordance with the PSB's approval of the Vermont Yankee sale. The purpose of those filings was to determine whether a rate decrease was warranted in either year as a result of the sale of the Vermont Yankee plant. In July 2003, the Company reached a MOU with the DPS regarding that filing. The agreement concluded that: 1) a rate decrease was not warranted; 2) the Company would decrease its allowed return on common equity from 11 percent to 10.5 percent effective July 1, 2003; 3) any earnings over the allowed cap of 10.5 percent would be applied to reduce deferred charges on the balance sheet; 4) the Company would file a fully allocated cost of service plan and a proposed rate redesign; and 5) the Company agreed to work cooperatively with the DPS to develop and propose an alternative regulation plan.

Hearings on the MOU were conducted by the PSB in December 2003, and the PSB issued an Order on January 27, 2004 providing conditional approval for the MOU. It included the following significant modifications: 1) that the return on common equity be reduced to 10.25 percent; 2) starting January 1, 2004 the Company would begin new amortizations of deferred charges on the balance sheet at December 31, 2003 of about $2.5 million annually; and 3) that the Company would file with the PSB a proposal to apply the $21 million payment it received from PSNH, in connection with the Connecticut Valley sale, to write down deferred charges.

The MOU and PSB Order are not binding on the Company. On February 3, 2004, the Company filed a Request for Reconsideration and Clarification. On February 12, the Company filed information with the PSB in response to PSB information requests. The Company has been advised that the PSB will schedule a workshop in March 2004 to review the Company's filing. The MOU and related Request for Reconsideration and Clarification are still in the regulatory process and the Company cannot predict the outcome of that process at this time.

Mandated Earning Cap: The Vermont utility earnings were above the allowed rate of return on common equity of 11 percent for the 12 months ended December 31, 2003, resulting in a $1.5 million, after-tax, reduction of the Vermont utility's earnings, to stay below the mandated earnings cap. Similarly, in 2002 the Vermont utility earnings were reduced by about $0.4 million, after-tax. The Company recorded related pre-tax regulatory liabilities amounting to about $2.5 million in 2003 and $0.7 million in 2002, which are expected to be used to decrease deferred charges on the balance sheet at December 31, 2003.

In October 2002, the Company and NHPUC asked FERC to withhold its final exit fee order so the parties could continue to negotiate a settlement. In October 2003, FERC approved termination of the wholesale power contract and related exit fee proceedings upon completion of the sale.

Wheelabrator Power Contract Connecticut Valley purchased power from several independent power producers, who own qualifying facilities as defined by the Public Utility Regulatory Policies Act of 1978. In 2003 Connecticut Valley bought 38,700 mWh under long-term contracts with these facilities, 94 percent from Wheelabrator Claremont Company, L.P., ("Wheelabrator") which owns a trash-burning generating facility. Connecticut Valley had filed a complaint with FERC related to its concern that Wheelabrator had not been a qualifying facility since it began operation. FERC denied that complaint and later denied an appeal, so Connecticut Valley sought relief from the NHPUC. In April 2002 Connecticut Valley and other parties submitted a settlement to the NHPUC. The January 1, 2004 sale described above resolved this issue.

POWER RESOURCES

Overview

The Company's and Connecticut Valley's energy generation and purchased power required to serve their retail and firm wholesale customers was 2,552,827 mWh for the year ended December 31, 2003. The maximum one-hour integrated demand during that period was 417.2 mW, which occurred on December 2, 2003. The Company's and Connecticut Valley's total energy generation and purchased power in 2003, including that related to all resale customers, was 3,062,471 mWh.

The following table shows the sources of such energy and capacity available to the Company and Connecticut Valley for the year ended December 31, 2003. For additional information related to purchased power costs, refer to PART II Item 7, herein.

	Year Ended December 31, 2003		
	Net Effective Capability 12 Month Average	Generated and Purchased	
	MW	mWh	%
Wholly Owned Plants			
Hydro	40.7	174,050	5.6
Diesel and Gas Turbine	28.1	2,065	0.1
Jointly Owned Plants			
Millstone #3	19.8	172,728	5.5
Wyman #4	10.9	17,745	0.6
McNeil	10.5	46,050	1.5
Major Long Term Purchases			
Vermont Yankee (a)	181.6	1,547,770	49.9
Hydro-Quebec	142.8	826,104	26.6
Other Purchases			
System and other purchases	43.0	2,813	0.1
Independent power producers	28.7	164,918	6.6
NEPOOL (ISO-New England)	0.0	108,228	3.5
Total	506.1	3,062,471	100.0

(a) Approximately 60 percent of the mWh generated and purchased from Vermont Yankee were prior to the July 31, 2002 sale of the plant, in which the Company had an equity ownership in the plant. The remaining purchases occurred after the sale under a purchased power agreement as described in more detail below.

Wholly Owned Plants

The Company owns and operates 20 hydroelectric generating facilities in Vermont, which have an aggregate nameplate capability of 44.7 MW and two oil-fired gas turbines and one diesel-peaking unit with a combined nameplate capability of 28.9 MW.

Jointly Owned Plants

The Company has joint-ownership interests in the following generating and transmission plants:

Name	Location	Fuel Type	Ownership	MW Entitlement	Net Generation mWh	2002 Load Factor	Net Plant Investment
Millstone Unit #3	Waterford, CT	Nuclear	1.73%	20.0	172,728	98.6%	$43,004,303
Wyman #4	Yarmouth, ME	Oil	1.78%	11.0	17,745	18.4%	$1,059,115
Joseph C. McNeil	Burlington, VT	Various	20.00%	10.6	46,050	49.6%	$5,613,915
Highgate Transmission Facility	Highgate Springs, VT		47.35%	N/A	N/A	N/A	$7,483,089

The Company receives its share of output and capacity of Millstone Unit #3, a 1,157 MW nuclear generating facility (see discussion below); Wyman #4, a 615 MW generating facility and Joseph C. McNeil, a 53 MW generating facility.

The Highgate Converter, a 225 MW facility is directly connected to the Hydro-Quebec System to the north of the Converter and to the VELCO System for delivery of power to Vermont Utilities. This facility can deliver power in either direction, but normally delivers power from Hydro-Quebec to Vermont.

The Company is responsible for its share of the operating expenses of these facilities.

Major long-term power purchase commitments

Hydro-Quebec The Company is purchasing varying amounts of power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract through 2016. The VJO includes a group of Vermont electric companies and municipal utilities, of which the Company is a participant. Related contracts were 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.

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 balance of the VJO participants, including the Company, will "step-up" to the defaulting party's share on a pro rata basis. As of December 31, 2003, the Company's obligation is approximately 46 percent of the total VJO Power Contract through 2016, which translates to approximately $734 million, on a nominal basis. The average annual amount of capacity that the Company will purchase from January 1, 2004 through October 31, 2012 is approximately 144.2 MW, with lesser amounts purchased through October 31, 2016. See PART II Item 8, Note 13 for additional information regarding the Hydro-Quebec contract.

Vermont Yankee The Company has a 35 percent entitlement in Vermont Yankee output sold by Entergy Nuclear Vermont Yankee, LLC ("Entergy") to Vermont Yankee, through a long-term power purchase contract with Vermont Yankee. One remaining secondary purchaser continues to receive a small percentage of the Company's entitlement. The long-term contracts between Vermont Yankee and the Company and between Vermont Yankee and Entergy became effective on July 31, 2002, the same day that the Vermont Yankee nuclear plant was sold to Entergy. The Company is responsible for the purchase of replacement power to the extent required to serve its load when the plant is not operating due to scheduled or unscheduled outages.

The purchased power contract ("PPA") in which Vermont Yankee purchases power from Entergy and in turn sells to the Company and other parties includes prices that generally range 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" that protects the current Vermont Yankee entitlement holders, including the Company and its power consumers, if power market prices drop significantly. If the market prices rise, however, contract prices are not adjusted upward. The PPA is expected to result in decreased costs over the life of the PPA when compared to continued ownership of the plant. See PART II Item 8, Note 13 for additional information regarding Vermont Yankee.

Other Purchases

Cogeneration/Independent Power Qualifying Facilities The Company receives power from several Independent Power Producers ("IPPs"). These plants use water, biomass and trash as fuel. Most of the power comes through a state-appointed purchasing agent, VEPP Inc. ("VEPPI"), which assigns power to all Vermont utilities under PSB rules. In 2003, the Company received 164,918 mWh under these long-term contracts, including 142,968 mWh received through VEPPI. These IPP purchases account for 6.2 percent of the Company's total mWh purchased and 11 percent of purchased power costs. See Part II Item 8, Note 13 for additional information related to Independent Power Producers.

NEPOOL and ISO-New England The Company, represented by VELCO, is a participant in NEPOOL, which has been open to all investor-owned, municipal, and cooperative utilities in New England under an agreement in effect since 1971 and amended from time to time. The Restated NEPOOL Agreement offers membership privileges to any entity engaged or proposing to engage in the wholesale or retail electric power business in New England. NEPOOL continues to exist as the entity representing not only traditional electric utilities but companies that participate in the emerging competitive wholesale electricity marketplace. A new not-for-profit organization, New England Independent System Operator ("ISO-New England"), was established in July 1997, following FERC approval, and immediately assumed responsibility for the management of the New England region's power grid and transmission systems and administering the region's open access tariff. ISO-New England was formed by transferring staff and equipment from NEPOOL to the new organization. ISO-New England has a service contract with NEPOOL to operate the bulk power system and to administer the wholesale marketplace.

ISO-New England is governed by FERC, including the principles put forth in FERC Order No. 888, under rules defined by NEPOOL and approved by FERC. They include, providing independent, open and fair access to the regional transmission system, establishing a non-discriminatory governance structure, facilitating market-based wholesale electric transactions, and ensuring the efficient management and reliable operation of the regional bulk power system.

On March 1, 2003, ISO-New England moved to a new market structure referred to as Standard Market Design ("SMD"), a significant step to restructuring the wholesale energy markets in the Northeast. See PART II, Item 7 herein for additional information regarding SMD and Regional Transmission Organizations.

NEPOOL's peak for the year occurred on August 22, 2003 and totaled 24,762 MW. The Company's peak demand occurred on December 2, 2003 and totaled 417.2 MW; the Company had a reserve margin of approximately 18.9 percent, at the time of this peak.

Power Resources - Future

The Company engages in short-term purchases and sales in the wholesale markets administered by ISO-New England and with other third parties, primarily in New England, to minimize net power costs and risks to our customers. The Company's long-term power forecast reflects energy amounts in excess of that required to meet load requirements; therefore net power costs are dependent, in part, upon wholesale power market prices. Additionally, the January 1, 2004, sale of Connecticut Valley's assets and termination of its power contract released an average of about 11 MW on-peak and 17 MW off-peak of the Company's power supply mix for future disposition.

On an hourly basis, power is sold or bought through ISO-New England to balance the Company's resource output and load requirements. From time to time, the Company enters into forward sale transactions in order to reduce volatility of forecasted power costs. The Company may also enter into forward purchase transactions, when its forecasts reflect deficiencies such as scheduled refueling outages at Vermont Yankee. See Part II Item 7, herein.

NUCLEAR DECOMMISSIONING COSTS

The Company is one of several sponsor companies with ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. The Company is responsible for paying its ownership percentage of decommissioning and all other costs for each plant. These companies have permanently shut down generating activities and are conducting decommissioning activities. The Company also has a 1.7303 percent joint-ownership interest in Millstone Unit #3. The Company's obligations related to the eventual decommissioning of the Vermont Yankee plant ceased when the plant was sold to Entergy on July 31, 2002.

Millstone Unit #3 The Company has an external trust dedicated to funding its joint ownership share of future decommissioning for Millstone Unit # 3. Contributions to the Millstone Unit #3 Trust Fund have been suspended based on the lead owner's representation to various regulatory bodies that the Trust Fund, for its share of the plant, exceeded the Nuclear Regulatory Commission's minimum calculation required. The Company could choose to renew funding at its own discretion as long as the minimum requirement is met or exceeded.

Maine Yankee, Connecticut Yankee and Yankee Atomic The Company's share of estimated future payments related to the decommissioning of Maine Yankee, Connecticut Yankee and Yankee Atomic, based on current forecasts for each plant, are as follows (dollars in millions):

	Date of Study	Total Obligation (a)	Remaining Obligation (b)	Revenue Requirements (c)	Company Share (d)
Maine Yankee	2003	$695.0	$220.7	$364.4	$7.4
Connecticut Yankee	2003	$1,004.7	$543.9	$666.4	$13.3
Yankee Atomic	2003	$667.3	$237.4	$181.3	$7.5

(a) Estimated total decommissioning cost for each plant in 2003 dollars.
(b) Estimated remaining decommissioning costs in 2003 dollars for the period 2004 through 2023 for Maine Yankee and Connecticut Yankee, and through 2022 for Yankee Atomic.
(c) Estimated future payments required by the Sponsor companies to recover estimated decommissioning and all other costs for 2004 and forward, in nominal dollars. For Maine Yankee and Connecticut Yankee includes collections for required contributions to spent fuel funds as described below. Yankee Atomic has already collected and paid these required contributions.
(d) Represents the Company's share of revenue requirements based on its ownership percentage in each plant. For Yankee Atomic, this includes $1.1 million related to 2003. See discussion below for more detail.

Maine Yankee, Connecticut Yankee and Yankee Atomic are seeking recovery of fuel storage related costs stemming from the default of the United States Department of Energy ("DOE") under the 1983 fuel disposal contracts that were mandated by the United States Congress under the High Level Waste Act. These damage claims are now pending in the Federal Court of Claims. The trial is expected to begin in July 2004. The fuel storage related costs associated with the damage claims are included in each company's estimated total obligation, shown in the table above. None of the plants have included any allowance for potential recovery of these claims in their estimates.

The Company's share of each plant's estimated revenue requirements are reflected in the Company's Consolidated Balance Sheets as regulatory assets or other deferred charges, and nuclear decommissioning liabilities (current and non-current). At December 31, 2003, the Company had regulatory assets of about $7.4 million related to Maine Yankee and $3 million related to Connecticut Yankee. These estimated costs are being collected from the Company's customers through existing retail and wholesale rate tariffs. At December 31, 2003, the Company also had other deferred charges of about $10.3 million related to incremental dismantling costs for Connecticut Yankee and $7.5 million for Yankee Atomic. These amounts are not currently being collected from customers through existing rates. On October 29, 2003, the PSB approved an Accounting Order for treatment of these incremental costs as other deferred charges, to be addressed in its next rate proceeding. The Company will adjust the associated regulatory assets, other deferred charges and nuclear decommissioning liabilities when revised estimates are provided.

Maine Yankee: The Company has a 2 percent ownership interest in Maine Yankee. Costs billed by Maine Yankee are expected to change due to their October 21, 2003 filing at FERC. Maine Yankee's current billings to sponsor companies are based on their rate case settlement approved by FERC on June 1, 1999 under which costs were to be recovered through October 2008. In that settlement, Maine Yankee agreed to file a FERC rate proceeding with an effective date for new rates no later than January 1, 2004. In the current filing the cost recovery period is proposed to extend to 2010.

Connecticut Yankee: The Company has a 2 percent ownership interest in Connecticut Yankee. Costs currently billed by Connecticut Yankee are based on its most recent FERC-approved rates, which became effective September 1, 2000, for collection through 2007. These amounts are being collected from the Company's customers through existing rates.

Connecticut Yankee is involved in a contract dispute with Bechtel Power Corporation ("Bechtel"), which resulted in termination of the decommissioning services contract between Connecticut Yankee and Bechtel. This is a commercial contract dispute regarding Bechtel's performance; it is not related to safety, security or workmanship issues. As a result of contract termination, on July 14, 2003, Connecticut Yankee became the general contractor for the decommissioning.

On June 23, 2003, Bechtel responded to the notice of termination by filing a complaint for breach of contract, misrepresentation, and bad faith, in Connecticut Superior Court. After the contract termination, Bechtel amended its complaint to allege additional contract breaches (including wrongful termination) by Connecticut Yankee.

On August 22, 2003, Connecticut Yankee formally denied the allegations of Bechtel's amended complaint and filed a counterclaim. It alleges various material breaches of contract that justified Bechtel's termination, along with misrepresentation and bad faith. It also requests that Bechtel be found responsible for project costs in excess of Bechtel's unpaid contract balance, and for other damages. The lawsuit has been assigned to the Complex Litigation Docket and has been set for a jury trial beginning May 4, 2006. Connecticut Yankee also notified Bechtel's surety of its intention to file a claim under the performance bond.

At Connecticut Yankees' December 2003 Board of Directors meeting, the Board endorsed an updated estimate of the costs for the plant's decommissioning project. This updated cost estimate referred to as the "2003 Estimate" of approximately $823 million, covers the time period 2000 through 2023 and represents an aggregate increase of approximately $413 million in nominal dollars over the cost estimate in its 2000 FERC rate case settlement, which covered the same time period. It also includes increased costs from a November 2002 updated estimate which were related to projected costs of spent fuel storage, security, and liability and property insurance. The 2003 Estimate represents an increase of about $389 million in 2003 dollars. Prior to the approval of the cost estimate in the 2000 FERC settlement, Connecticut Yankee had also incurred about $184 million for decommissioning costs in the 1997 - 1999 timeframe.

The 2003 Estimate is still undergoing review; it reflects the fact that Connecticut Yankee is now directly managing the work (self performing) to complete decommissioning of the plant following the default termination of Bechtel as described above. Connecticut Yankee intends to update the estimate based on additional information when available including the results of competitive bidding of project work such as demolition. The 2003 Estimate does not include any allowance for relief of the Bechtel contract dispute or the DOE damage claim described above.

Connecticut Yankee is also beginning the preparation of a rate case application that is required to be filed with FERC by July 1, 2004 under the terms of its 2000 FERC rate case settlement. While Connecticut Yankee has not determined the relief it will seek in the forthcoming application, it anticipates that annual decommissioning collections would have to be increased significantly, beginning January 2005, to support anticipated project cash flow over the next several years and to fund long-term fuel storage through 2023.

The Company's estimated aggregate obligation related to Connecticut Yankee is about $13.3 million. The timing, amount and outcome of these filings cannot be predicted at this time. The Company believes its share of Connecticut Yankee's decommissioning costs are probable of recovery in future rate proceedings.

Yankee Atomic: The Company has a 3.5 percent ownership interest in Yankee Atomic. Billings to the Company ended in July 2000 based on Yankee Atomic's determination that it had collected sufficient funds to complete the decommissioning effort. The Company is not currently collecting Yankee Atomic costs in retail rates.

In late 2002, Yankee Atomic revised its cost estimate for decommissioning the plant, reflecting an increase of about $190 million over prior estimates utilized by FERC. The increase was attributable to increases in projected costs of spent fuel storage, security, and liability and property insurance. In April 2003, Yankee Atomic filed with FERC for new rates to collect these costs from sponsor companies. FERC approved the resumption of billings starting June 2003 for a recovery period through 2010, subject to refund. The Company expects its share of these costs will be recoverable in future rates. In 2003, Yankee Atomic's billings to the Company amounted to about $1.1 million. Based on a PSB-approved accounting order, the Company is deferring these costs.

Nuclear Liability and Insurance

The Price-Anderson Act ("Act") currently limits public liability from a single incident at a nuclear power plant to approximately $10 billion. This protection consists of two levels. 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 retrospective premium, equal to its proportionate share of the excess loss, up to a maximum of $100.6 million per reactor per incident, limited to a maximum annual assessment of $10 million. The maximum assessment is adjusted at least every five years to reflect inflation. The Act has been renewed since it was first enacted in 1957, and expired in August 2002. Amendments to the Act were included in the Energy Policy Act of 2003, which was not passed. However, liability coverage purchased by existing commercial nuclear power plants under the Act is not affected by the expiration date. Currently, based on its joint-ownership interest in Millstone Unit #3, the Company could become liable for about $0.2 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. The Company's obligations under this Act for Vermont Yankee ended with the July 2002 sale of the plant.

TRANSMISSION

VELCO

VELCO engages in the operation of a high-voltage transmission system, which interconnects electric utilities in the State including areas served by the Company. VELCO is also engaged in the business of purchasing bulk power for resale, at cost, to the Company and the other electric utilities (cooperative, municipal and investor-owned) in Vermont (the "Vermont utilities") and transmitting such power for the Vermont utilities. VELCO operates pursuant to the terms of the 1985 Four-Party Agreement, as amended, with the Company and two other major distribution companies in Vermont. Although the Company owns 50.5 percent of VELCO's outstanding common stock, the Four-Party Agreement does not provide the Company the ability to exercise control over VELCO.

VELCO provides transmission services for the State of Vermont, acting by and through the DPS, and for all of the electric distribution utilities in the State of Vermont. VELCO is reimbursed for its costs (as defined in the agreements relating thereto) for transmission of power for such entities. The Company, as the largest electric distribution utility in Vermont, is the major user of VELCO's transmission system.

The Company owns 56.8 percent of VELCO's outstanding Class B voting common stock, 31.45 percent of VELCO's outstanding Class C non-voting common stock (approved by the FERC on July 15, 2002), and 46.6 percent of VELCO's outstanding Class C preferred stock. Shares of Class C preferred stock have no voting rights except the limited right to vote VELCO's shares of common stock in VETCO if certain dividend requirements are not met.

NEPOOL Arrangements

VELCO is a participant with all of the major electric utilities in New England in the New England Power Pool ("NEPOOL"), acting for itself and as agent for the Company and twenty-one other Vermont utilities, whereby the generating and transmission facilities of all of the participants are coordinated on a New England-wide basis through a central dispatching agency to assure their operation and maintenance in accordance with proper standards of reliability, and to attain the maximum practicable economy for all of the participants through the interchange of economy and emergency power.

At this time, much of the cost of New England's existing and new high-voltage transmission system (115 kV looped facilities) are shared by all New England utilities. VELCO is planning several significant upgrades, which have been approved by the New England Power Pool for shared cost treatment. Vermont has traditionally been a significantly higher than average transmission cost jurisdiction. The new approach is advantageous to the Company's cost and reliability in providing service to its customers because our load share is a small fraction of total New England load, and the facilities VELCO is planning improve both the reliability and efficiency (i.e., losses and congestion) of the transmission network. We will pay a share of such projects elsewhere in New England but the net economic effect is expected to be beneficial, and better reliability elsewhere in the region benefits Vermont's reliability because of the highly integrated nature of New England's high voltage network. However, the cost of other future transmission facilities that do not qualify for cost sharing will be charged only to the requesting entity and our share of such costs will be affected by FERC approved cost-allocation rulings contained in VELCO and the Company's tariffs and agreements. See Part II Item 7, herein.

Capitalization

At December 31, 2003, VELCO has authorized 92,000 shares of Class B common stock, $100 par value, of which 60,000 shares were outstanding; 20,000 shares of Class C common stock, $100 par value, of which 19,901 were outstanding; and 125,000 shares of Class C preferred stock, $100 par value, of which 97,068 shares were outstanding. In addition, three issues of First Mortgage Bonds, aggregating $50,341,000 issued under an Indenture of Mortgage dated as of September 1, 1957, as amended, between VELCO and Bankers Trust Company, as Trustee (the "VELCO Indenture") were authorized and outstanding at December 31, 2003. The issuance of bonds under the VELCO Indenture is unlimited in amount but is subject to certain restrictions.

Management

In 1957 VELCO entered into an agreement (the "Three-Party Agreement") whereby the Company and GMP agreed that, if VELCO transmits firm power it owns (which VELCO does not now do), VELCO would have the right to purchase all such firm power not sold to others. As such, VELCO would have the obligation to pay associated operating expenses, debt service and taxes.

The Company and GMP entered into a Three-Party Transmission Agreement, dated November 21, 1969. Under this Agreement, as amended, the Company and GMP agreed to pay transmission charges thereon in an aggregate amount sufficient, with VELCO's other revenues, to pay all of VELCO's expenses including capital costs. VELCO's Bonds are secured by a first mortgage on the major part of VELCO's transmission properties and by the assignment to the Trustee of the Three-Party Agreement, the Three-Party Transmission Agreement and certain other contracts as specified in the VELCO Indenture.

VELCO operates pursuant to the terms of the 1985 Four-Party Agreement (as amended) with the Company and two other major distribution companies in Vermont. Although the Company owns 50.5 percent of VELCO's outstanding common stock, the Four-Party Agreement does not provide the Company ability to exercise control over VELCO.

VETCO

In connection with importing Canadian power, VELCO created a wholly owned subsidiary, VETCO, to construct, finance, own and operate the Vermont portion of the transmission line which connects the Hydro-Quebec lines at the Canadian border to lines of New England Electric Transmission Corporation, a subsidiary of National Grid USA, formerly New England Electric System, at the New Hampshire border on the Connecticut River. VETCO entered into a Capital Funds Agreement with VELCO pursuant to which VETCO may request up to $12,500,000 (of which $10,000,000 was contributed as of December 31, 2003) of capital contributions from VELCO. VETCO also entered into Transmission Line Support Agreements with 20 New England utilities, including VELCO as representative for 14 Vermont utilities, pursuant to which those utilities have agreed to pay the transmission line costs, whether or not the line is operational. VELCO, as representative, has entered into a similar agreement with New England Electric Transmission Corporation with respect to the New Hampshire portion of the DC transmission line and the DC/AC converter station. Pursuant to a Vermont Participation Agreement and a Capital Funds Support Agreement with VELCO and 14 Vermont electric distribution utilities, including the Company, assume their pro rata share (based upon 1980 sales) of the benefits and obligations of VELCO under the Support Agreements and the VETCO Capital Funds Agreement.

VETCO has authorized 10 shares of common stock, $100 par value, all of which were outstanding on December 31, 2003 and owned by VELCO, with each share having one vote. During 1986 VETCO paid off its construction financing by issuing $37,000,000 of secured notes, maturing in 2006, and receiving a $9,999,000 equity contribution from VELCO. The notes are secured by a First Mortgage on the major part of VETCO's transmission properties and by the assignment of its rights under the Support Agreements.

Phase I and Phase II

The Company participated with other electric utilities in construction of the Phase I Hydro-Quebec interconnection transmission facilities in northeastern Vermont, which were completed at a total cost of approximately $140 million. Under a support agreement relating to the Company's participation in the facilities, the Company is obligated to pay its 4.55 percent share of Phase I Hydro-Quebec capital costs over a 20-year recovery period through and including 2006. The Company also participated in the construction of Phase II Hydro-Quebec transmission facilities constructed throughout New England, which were completed at a total cost of approximately $487 million. This service increased maximum capacity of the Hydro-Quebec 450 kV DC facilities from 690 MW to 2000 MW and extended the Phase I line from Comerford, New Hampshire to Sandy Pond, Massachusetts. The Company uses this transmission path to deliver a portion of the Company's long-term Hydro-Quebec firm power contract. Under a similar support agreement, the New England participants, including the Company, have contracted to pay their proportionate share of the total cost of constructing, owning and operating the Phase II facilities, including capital costs. The Company is obligated to pay its 5.132 percent share of Phase II Hydro-Quebec capital costs over a 25-year recovery period through and including 2015.

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 investment 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 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. An initial set of rules for DUP was filed by the parties in Docket No. 6290 as a Memorandum of Understanding, which was approved by the PSB on January 15, 2003. It provides: 1) an energy efficiency screening tool that is under development; 2) an agreement on default planning assumptions that are subject to modification semi-annually as well as changes to fit specific area conditions; 3) continued collaboration of the parties to update the rules as necessary and to share information; and 4) an ongoing collaborative for a number of area specific collaboratives ("ASC") to examine resource investment options for potentially constrained transmission or distribution areas; the Company has five such ASCs.

DIVERSIFICATION

Catamount Resources Corporation was formed for the purpose of holding the Company's subsidiaries that invest in unregulated business opportunities. One of its subsidiaries, Catamount Energy Corporation, invests through its wholly owned subsidiaries in non-regulated energy generation projects in the United States and United Kingdom. Another of its subsidiaries, 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.

EMPLOYEE INFORMATION

Local Union No. 300, affiliated with the International Brotherhood of Electrical Workers represents operating and maintenance employees of the Company and Connecticut Valley Electric Company. On December 31, 2003 the Company and its wholly owned subsidiaries including Catamount, employed 535 persons, of which 217 are represented by the union. On December 27, 2001, the Company and its employees represented by the union agreed to a new three-year contract, which expires on December 31, 2004. The new contract provided for a net general wage increase of 3 percent effective December 30, 2001, December 29, 2002 and January 4, 2004, enhanced pension benefits and employee contributions for health-care coverage will increase from 7 to 20 percent of the cost over the three year period of the new contract.

SEASONAL NATURE OF BUSINESS

In general, the Region tends to experience its peaks in summer months. Winter recreational activities, longer hours of darkness and heating loads from cold weather usually causes the Company's maximum loads of electric mWh sales to occur in January or late December, while air conditioning contributes to peaks in the summer.

CAPITAL EXPENDITURES

The Company's capital expenditures totaled approximately $15 million in 2003, $13.9 million in 2002 and $16.1 million in 2001. The Company's five-year capital expenditures for the Vermont utility business are expected to range from approximately $85 million to $95 million for the years 2004 through 2008. This estimate is subject to continuing review and adjustment and actual capital expenditures may vary from this estimate. For additional information regarding capital expenditures and working capital see Part II, Item 7 herein.

OFFICERS

The following sets forth the present Executive Officers of the Company. There are no family relationships among the executive officers. Officers are normally elected annually.

Executive Officers of the Registrant:

Name and Age	Office	Officer Since
Robert H. Young, 56	President and Chief Executive Officer	1987
William J. Deehan, 51	Vice President -Transmission and Generation Planning and Regulatory Affairs	1991
Joan F. Gamble, 46	Vice President - Strategic Change and Business Services	1998
Jean H. Gibson, 47	Senior Vice President, Chief Financial Officer, and Treasurer	2002
Joseph M. Kraus, 49	Senior Vice President Engineering and Operations	1987
Dale A. Rocheleau, 45	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; AgEnergy, Inc.; SmartEnergy Water Heating Services, Inc.; and, Chair of Catamount Energy Corporation. 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. 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. Mr. Deehan also serves as Vice President - Transmission and Generation Planning and Regulatory Affairs of Connecticut Valley Electric Company Inc., a CVPS subsidiary.

Ms. Gamble joined the Company in 1989. Prior to being elected to her present position in August 2001, she was Director of Marketing Research & Planning from 1989 to 1996; Director of Strategic and Policy Planning from 1996 to September 1997; Director of Human Resources and Strategic Planning from September 1997 to May 1998; Assistant Vice President Human Resources and Strategic Planning from May 1998 to May 2000; and, Vice President - Human Resources and Strategic Planning from May 2000 to August 2001. Ms. Gamble also serves as Vice President - Strategic Change and Business Services for the following CVPS subsidiaries: Connecticut Valley Electric Company Inc.; Eversant Corporation; and, Catamount Energy Corporation. She serves as a Director for the following CVPS subsidiaries: Eversant Corporation; AgEnergy, Inc.; and, SmartEnergy Water Heating Services, Inc.

Ms. Gibson joined the Company in 2002. Prior to joining the Company, from 2000 to 2002, she served as Corporate Vice President and Controller at Exelon Corporation; from 1998 to 2000 she served as Corporate Vice President and Controller at PECO Energy Company. Ms. Gibson serves as Director, Senior Vice President, Chief Financial Officer, and Treasurer for the following CVPS subsidiaries: CVPSC - East Barnet Hydroelectric, Inc.; CV Realty, Inc.; Custom Investment Corporation; Catamount Resources Corporation; Eversant Corporation; and, SmartEnergy Water Heating Services, Inc. She also serves as Senior Vice President, Chief Financial Officer, and Treasurer for the following CVPS subsidiaries: Connecticut Valley Electric Company Inc. and AgEnergy, Inc. and Senior Vice President and Chief Financial Officer of Catamount Energy Corporation.

Mr. Kraus joined the Company in 1981. Prior to being elected to his present position of Senior Vice President Engineering and Operations, he served as Corporate Secretary and General Counsel commencing in 1994; Vice President, Corporate Secretary, and General Counsel commencing in 1996; Senior Vice President, Corporate Secretary, and General Counsel commencing in 1999; Senior Vice President Customer Service, Secretary, and General Counsel commencing in 2001; and, Senior Vice President Engineering and Operations, General Counsel, and Secretary from May 2003 until November 2003. Mr. Kraus serves as Director of the following CVPS subsidiaries: CVPSC - East Barnet Hydroelectric, Inc.; CV Realty, Inc.; Custom Investment Corporation; Catamount Resources Corporation; Eversant Corporation; AgEnergy, Inc.; and, SmartEnergy Water Heating Services, Inc. He also serves as Senior Vice President Engineering and Operations for the following CVPS subsidiaries: Connecticut Valley Electric Company 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 also serves as Senior Vice President and General Counsel for Catamount Energy Corporation, a CVPS subsidiary.

The term of each officer is for one year or until a successor is elected.

Item 2. Properties.

The Company The Company's properties are operated as a single system which is interconnected by the transmission lines of VELCO, NEP and PSNH. 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 1.78 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 1.73 percent interest in a nuclear generating plant in Connecticut; and a 47.35 percent interest in a transmission interconnection facility in Vermont.

The electric transmission and distribution systems of the Company include about 617 miles of overhead transmission lines, about 7,826 miles of overhead distribution lines and about 339 miles of underground distribution lines, all of which are located in Vermont except for about 22 miles in New Hampshire and about two miles in New York.

Connecticut Valley On January 1, 2004, Connecticut Valley completed the sale of substantially all of its plant assets and its franchise to PSNH. Connecticut Valley's electric properties consisted of two principal systems in New Hampshire which are not interconnected; each system, however, is connected directly with facilities of the Company.

The electric systems of Connecticut Valley included about two miles of transmission lines, about 446 miles of overhead distribution lines and about 14 miles of underground distribution lines.

All of the principal plants and important units of the Company and its subsidiaries are held in fee. Transmission and distribution facilities, which are not located in or over public highways are, with minor exceptions, located on either 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.

VELCO VELCO's properties consist of about 483 miles of high voltage overhead 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 north with lines of Hydro-Quebec through a converter station and tie line jointly owned by the Company and several other Vermont utilities.

VETCO VETCO has approximately 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 the results of operations, except as otherwise disclosed herein.

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

There were no matters submitted to security holders during the fourth quarter of 2003.

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters.

(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
2003		
First Quarter	$ 19.00	$ 16.52
Second Quarter	19.95	17.00
Third Quarter	22.99	19.40
Fourth Quarter	24.50	22.10
2002		
First Quarter	$ 18.38	$ 16.00
Second Quarter	19.66	16.41
Third Quarter	18.20	15.69
Fourth Quarter	18.87	16.80

(b) As of December 31, 2003, there were 8,720 holders of the Company's Common Stock, $6 par value.

(c) Common Stock dividends have been declared quarterly. Cash dividends of $.22 per share were paid for all quarters of 2002 and 2003.

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, 2003, the Common Stock Equity of the unconsolidated Company was 58.4 percent of total capitalization.

Several of the Company's indentures relating to its First Mortgage Bonds contain certain restrictions on the payment of cash dividends on capital stock and other Restricted Payments (as defined). The most restrictive of these provisions limit 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 Article 1 Section 18 of the Forty-Second Supplemental Indenture dated June 11, 2001; such definitions are based upon the unconsolidated financial statements of the Company. As of December 31, 2003, $88 million was available for such Restricted Payments.

Under the Company's Second Mortgage Indenture, certain restrictions on the payment of cash dividends on capital stock, other Restricted Payments (as defined) and Restricted Investments (as defined) would become effective if the Company's Second Mortgage Bonds are rated below investment grade. The defined terms identified above are used herein in the sense as defined in Article III Section 3.06 of the Second Supplemental Indenture dated December 1, 1999; such definitions are based upon the unconsolidated financial statements of the Company. Under the most restrictive of these provisions, $5.8 million was available for such Restricted Payments and Restricted Investments at December 31, 2003. For additional information regarding dividend payment level and dividend restrictions see Item 8 herein.

(d) The information required by this item is incorporated herein by reference to the Proxy Statement of the Company for the 2004 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 26, 2004.

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

For the year	**2003**	2002	2001	2000	1999
Operating revenues	**$306,014**	$294,390	$292,900	$333,926	$419,815
Income from continuing operations	**$18,355**	$18,224	$754	$18,043	$16,584
Income from discontinued operations	**$1,446**	$1,543	$1,653	-	-
Net income	**$19,801**	$19,767	$2,407	$18,043	$16,584
Earnings available for common stock	**$18,603**	$18,239	$711	$16,264	$14,722
Consolidated return on average common stock equity	**9.2%**	9.6%	0.4%	8.6%	7.9%
Common Stock Data					
Basic:					
Earnings (loss) per share from continuing operations	**$1.45**	$1.43	$(.08)	$1.42	$1.28
Earnings from discontinued operations	**.12**	.13	.14	-	-
Earnings per share	**$1.57**	$1.56	$.06	$1.42	$1.28
Diluted:					
Earnings (loss) per share from continuing operations	**$1.41**	$1.40	$(.08)	$1.41	$1.28
Earnings from discontinued operations	**.12**	.13	.14	-	-
Earnings per share	**$1.53**	$1.53	$.06	$1.41	$1.28
Cash dividends paid per share of common stock	**$.88**	$.88	$.88	$.88	$.88
Book value per share of common stock	**$17.57**	$16.83	$15.81	$16.57	$16.05
Net cash provided by operating activities of continuing operations	**$46,654**	$42,570	$30,216	$60,867	$31,232
Dividends paid	**$11,640**	$12,222	$11,433	$11,888	$11,950
Construction and plant expenditures	**$14,959**	$13,885	$16,148	$14,968	$13,231
Conservation and load management expenditures	**$104**	$236	$504	$1,136	$2,440
At End of Year					
Long-term debt (1)	**$126,750**	$137,908	$159,771	$152,975	$155,251
Capital lease obligations (1)	**$10,693**	$11,762	$12,897	$13,978	$15,060
Redeemable preferred stock (1)	**$9,000**	$10,000	$15,000	$16,000	$17,000
Total capitalization	**$365,748**	$365,332	$379,236	$381,704	$379,386
Total assets	**$531,319**	$540,849	$531,164	$539,838	$563,959

(1) Excluding current portion

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 intended to qualify for the safe-harbors from liability established by 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 regulators, performance of the Vermont Yankee nuclear power plant, effects of and changes in weather and economic conditions, volatility in wholesale power markets, our ability to maintain our current credit ratings, performance of our unregulated businesses, 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.

COMPANY OVERVIEW

We are a Vermont-based electric utility that transmits, distributes and sells electricity, and invests in renewable and independent power projects. We are regulated by the Vermont Public Service Board ("PSB"), the New Hampshire Public Utilities Commission ("NHPUC"), 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. On January 1, 2004, our wholly owned regulated subsidiary, Connecticut Valley Electric Company, Inc. ("Connecticut Valley"), sold its plant assets and franchise to Public Service Company of New Hampshire ("PSNH"). Prior to the sale, Connecticut Valley distributed and sold electricity in New Hampshire. Our wholly owned unregulated subsidiaries include: Catamount Energy Corporation ("Catamount"), which invests primarily in wind energy projects in the United States and United Kingdom; and Eversant Corporation ("Eversant"), which operates a rental water heater business through its subsidiary, SmartEnergy Water Heating Services, Inc.

The Vermont utility operation is our core business. Our retail rates are set by the PSB in conjunction with Vermont's consumer advocate, the Vermont Department of Public Service ("DPS"). Retail rates are designed to recover our costs of service and provide an allowed rate of return on common equity, which, based on our July 2001 rate case settlement, was capped at 11 percent for 2002 and 2003. While Vermont does not have a fuel or power adjustment clause, it is customary for the PSB to approve deferral of extraordinary costs incurred that might normally be expensed by unregulated businesses, in order to match these expenses with future revenues.

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 earnings streams. However, the ability to increase our customer base is limited to growth within the service territory, which has been flat for several years. Given the nature of our customer base, weather and economic conditions are factors that can significantly affect our retail sales revenue. We currently have sufficient power resources to meet our forecasted load requirements, mostly through long-term power contracts. The sale of Connecticut Valley's assets, discussed below, has made available an additional 11 MW on-peak and 17 MW off-peak of our power supply mix for disposition. We sell our excess power in the wholesale markets administered by ISO-New England or to third parties in New England. Such sales help to mitigate our overall power costs; but wholesale power market volatility can affect these mitigation efforts.

Vermont regulatory issues that remain unresolved are critically important to our business and a great deal of time is being spent to resolve those matters. In that regard, our top priority is the outstanding Memorandum of Understanding ("MOU") that is discussed in more detail below. In addition to the MOU, there are several State initiatives that could, over time, shift utility regulation away from cost-based regulation. These are discussed in Electric Industry Restructuring below.

In the fourth quarter of 2003, we received $14.3 million representing our share of cash proceeds related to the July 2002 sale of the Vermont Yankee nuclear power plant. The sale significantly improved our risk profile relative to generation given that we no longer bear the risks and costs associated with running the plant or the eventual decommissioning of the plant. On January 1, 2004, we received approximately $30 million related to the sale of

Connecticut Valley's plant assets and franchise, described in Discontinued Operations below. The sale, which became effective that day, resolved all Connecticut Valley restructuring litigation in New Hampshire and our stranded cost litigation at the FERC.

We are currently considering investment alternatives for these cash proceeds. The Vermont utility continues to generate sufficient cash flow to support ongoing operations. While Catamount has sufficient cash flow to cover its operating expenses, additional project investments will require financing or additional funding by the Company. Catamount is also seeking investors and partners to co-invest in the development, ownership and acquisition of projects.

Our Second Mortgage Bonds of $75 million mature on August 1, 2004. We are considering alternative refinancing arrangements. Currently, we intend to and have the ability to refinance the $75 million at maturity. The outcome of the MOU and perception of the 'regulatory environment' by the financial community may impact the terms and conditions associated with the refinanced debt.

VERMONT RETAIL RATES

Our current retail rates are based on a June 26, 2001 PSB Order approving a settlement with the DPS, which provided for, among other things, a 3.95 percent rate increase effective July 1, 2001. As part of the settlement, we also agreed to a $9 million write-off ($5.3 million after-tax) of regulatory assets and a rate freeze through January 1, 2003. The Order also: 1) ended uncertainty over Hydro-Quebec cost recovery by providing full cost recovery; 2) made the January 1, 1999 temporary rates permanent; 3) allowed a return on common equity of 11 percent for the year ending June 30, 2002 (capped through January 1, 2004); and 4) created new service quality standards. We are also required to return up to $16 million to ratepayers if there is a merger, acquisition or asset sale by the Company that requires PSB approval.

In April 2003, we were required to prepare cost of service studies for rate years 2003 and 2004, in accordance with the PSB's approval of the Vermont Yankee sale. The purpose of those filings was to determine whether a rate decrease was warranted in either year as a result of the sale of the Vermont Yankee plant. In July 2003, we agreed to a MOU with the DPS regarding that filing. The agreement concluded that: 1) a rate decrease was not warranted; 2) we would decrease our allowed return on common equity from 11 percent to 10.5 percent effective July 1, 2003; 3) any earnings over the allowed cap of 10.5 percent would be applied to reduce deferred charges on the balance sheet; 4) we would file a fully allocated cost of service plan and a proposed rate redesign; and 5) we would agree to work cooperatively with the DPS to develop and propose an alternative regulation plan.

Hearings on the MOU were conducted by the PSB in December 2003, and the PSB issued an Order on January 27, 2004 providing conditional approval for the MOU. It included the following significant modifications: 1) that the return on common equity be reduced to 10.25 percent; 2) starting January 1, 2004 we would begin new amortizations of deferred charges on the balance sheet at December 31, 2003 of about $2.5 million annually; and 3) that we would file with the PSB a proposal to apply the $21 million payment we received from PSNH, in connection with the Connecticut Valley sale, to write down deferred charges.

On February 3, 2004, we filed a Request for Reconsideration and Clarification of that Order. On February 12, 2004, we filed information with the PSB in response to PSB information requests. We have been advised that the PSB will schedule a workshop in March 2004 to review our filing. The MOU and related Request are still in the regulatory process and we cannot predict how it will be resolved at this time. However, if the outstanding MOU issues cannot be successfully resolved, it may result in a formal rate investigation commencing in 2004.

ELECTRIC INDUSTRY RESTRUCTURING

The State of Vermont is pursuing a variety of initiatives that are aimed at restructuring the provision of electric service without introducing retail choice. The following discussion highlights three initiatives of potential significance.

- The possible introduction of a mandatory Renewable Portfolio Standard ("RPS") that could require us to purchase certain amounts of our energy supply requirement from new renewable resources. We cannot determine whether, or if, a mandatory RPS will ultimately be adopted or required in Vermont. If the RPS proposed by the PSB were to be adopted, it would not require any changes in our power supply portfolio until January 1, 2013.

- The authorization of utility sponsored renewable pricing programs to permit customers to voluntarily elect to either purchase all or part of their electric energy from renewable sources; or cause the purchase and retirement of tradable renewable energy credits on the participating customer's behalf. In either case, the purpose of such pricing programs is to increase the utility's reliance on renewable sources of energy beyond those the utility would otherwise be required to provide in accordance with its Integrated Resource Plan as approved by the PSB. At this time, we are finalizing the terms of the renewable pricing program that we will file with the PSB for approval. The program will likely be priced in the form of a premium relative to the tariff that would otherwise apply. The premium would be cost-based so that it reasonably reflects the difference between acquiring the renewable energy and our alternative cost of power. The program will require that any costs of power in excess of our alternative cost of power will be borne solely by those customers who elect to participate in the renewable pricing program.
- The authorization of alternative forms of regulation for electric utilities that, besides other criteria, establish a reasonably balanced system of risks and rewards that encourages the utility to operate as efficiently as possible. The PSB may approve an alternative regulation plan only if it finds that the plan will not have an adverse impact on our eligibility for rate-regulated accounting in accordance with accounting principles generally accepted in the United States of America ("GAAP") and reasonably preserves the availability of equity and debt capital resources to us on favorable terms and conditions.

RISK FACTORS

Regulatory Risk In July 2003, we agreed to a MOU with the DPS described in more detail above. On January 27, 2004, the PSB issued its Order providing conditional approval for the MOU. The MOU and related issues are still pending. If the outstanding MOU issues cannot be successfully resolved, it may result in a formal rate investigation commencing in 2004.

Historically, electric utility rates in Vermont have been based on a utility's costs of service. As a result, electric utilities are subject to certain accounting standards that apply only to regulated businesses. Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71") allows regulated entities, including the Company, 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.

We believe the Company currently complies with the provisions of SFAS No. 71 for our regulated Vermont service territory and FERC-regulated wholesale businesses. If we determine the Company no longer meets the criteria under SFAS No. 71, the accounting impact would be an extraordinary charge to operations of about $41.8 million on a pre-tax basis as of December 31, 2003, assuming no stranded cost recovery would be allowed through a rate mechanism.

If retail competition is implemented in our Vermont service territory, we are unable to predict the impact on our revenues, our ability to retain existing customers with respect to their power supply purchases and attract new customers or the margins that will be realized on retail sales of electricity, if any such sales are sought.

Wholesale Power Market Risk Our material power supply contracts and arrangements are principally with Hydro-Quebec and Vermont Yankee Nuclear Power Corporation ("Vermont Yankee"). These contracts support about 90 percent of our total annual energy (mWh) purchases. Our exposure to market price volatility is limited for power supply purchases given that our long-term power forecast reflects energy amounts in excess of that required to meet load requirements. However, if one or both of these sources becomes unavailable for an extended period of time we would be subject to wholesale power price volatility and that amount could be material. Additionally, we rely on the sale of our excess power to help mitigate our overall net power costs. The volatility of wholesale power market prices can impact these mitigation efforts.

We also continue to monitor, and adapt to, changes to New England wholesale power markets and open access transmission systems. Related to the wholesale power markets, in March 2003, ISO-New England implemented Standard Market Design ("SMD"), a significant step to restructuring the wholesale energy markets in the Northeast. The move to regional transmission organizations ("RTO") also continues. SMD has impacted wholesale power prices, related to short-term sales and purchases as well as the costs of our owned generation. Although we expect that a transition to RTO will impact our transmission costs, we are not able to predict the nature of that impact.

Interest Rate Risk As of December 31, 2003, we have $16.3 million of Industrial Development/Pollution Control 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 lock or swap agreements in place. We have $55.2 million of consolidated temporary cash investments as of December 31, 2003, including $12.4 million of non-utility temporary cash investments. Interest rate changes could also impact calculations related to estimated pension and other benefit liabilities, affecting pension and other benefit expenses and potentially requiring contributions to the trusts.

Equity Market Risk As of December 31, 2003, our pension trust held marketable equity securities in the amount of $42.5 million and our Millstone Unit #3 decommissioning trust held marketable equity securities of $3.2 million. We also maintain a variety of insurance policies in a Rabbi Trust with a current value of $5.2 million to support various supplemental retirement and deferred compensation plans. The current values of certain policies are affected by changes in the equity market.

Credit Risk We have $16.9 million of letters of credit expiring on November 30, 2004. These letters of credit support three series of Industrial Development/Pollution Control Bonds, totaling $16.3 million. These letters of credit are secured by a first mortgage lien on the same collateral supporting our First Mortgage Bonds.

Based on outstanding debt at December 31, 2003, the amount of utility long-term debt maturities and sinking fund requirements is $75 million for the year 2004 related to our Second Mortgage Bonds, which mature on August 1, 2004. We are considering alternative refinancing arrangements. Currently, we intend to and have the ability to refinance the $75 million at maturity. No payments are due on long-term debt for 2005 through 2007. The 8.3 percent Dividend Series Preferred Stock is redeemable at par through a mandatory sinking fund of $1 million annually. In the fourth quarter of 2003, we recorded $2 million in Restricted Cash related to a December 31, 2003 payment to the Transfer Agent for the $1 million mandatory sinking fund payment for 2004 and a $1 million optional payment. The payment to the Preferred Shareholders was made effective January 1, 2004.

The covenants covering our Second Mortgage Bonds contain limiting restrictions if those bonds receive a debt rating below BBB- from rating agencies. The current ratings of the bonds are BBB- (stable) from Standard & Poor's and BBB (stable) from Fitch. The limiting characteristics include, but are not limited to, certain restrictions on investments in unregulated subsidiaries, the incurrence of indebtedness and the payment of dividends. These restrictions are dependent on meeting both a Fixed Charge Coverage and a Cumulative Cash Flow test, and we are currently in compliance with both calculations.

Inflation The annual rate of inflation, as measured by the Consumer Price Index, was 2.3 percent for 2003, 1.6 percent for 2002 and 2.8 percent for 2001. Our revenues are based on rate regulation that generally recognizes only historical costs; therefore, inflation continues to have an impact on most aspects of the business.

Unregulated Business In 2001, Catamount undertook a comprehensive strategic review of its operations. As a result, Catamount refocused its efforts from being an investor in late-stage renewable energy to being primarily focused on developing, owning and operating wind energy projects.

Catamount's future success is dependent on the acceptance of wind power as an energy source by large producers, utilities, and other purchasers of electricity. In addition, many potential customers believe that wind energy is an unpredictable and inconsistent resource, is uneconomic compared to other sources of power and does not produce stable voltage and frequency. There is no guarantee of wind power acceptance by potential customers as an energy source. The following highlights the wind-related risks that we believe are most critical to Catamount:

- *Wind Resource and Weather Pattern Risks* - The generation of electricity by wind energy projects is highly dependent on site wind conditions. Although wind energy projects are developed with careful review of available historic wind and weather patterns at a particular site, there is no assurance that Catamount can accurately forecast future long-term wind resource at any one site. In addition, average wind speeds and resource can vary widely in any year, resulting in significant annual revenue variability.

- *Power Purchase Agreement Risk* - Catamount will only develop or co-develop wind power projects that have power purchase agreements with acceptable third parties in place. The increased use of competitive bidding procedures has made obtaining power purchase agreements with utilities more competitive. Competitive bidding generally has reduced the price utilities pay independent power producers, which, in turn, reduces the profitability of many independent power projects.

- *Wind Turbine Generator Technology Risk* - The wind turbine generators ("WTGs") of the size Catamount intends to utilize have only been commercially available for two to three years. Long-term reliability of this equipment has yet to be proven. Wind turbine technology is rapidly changing with WTGs' growth in size and rated output every year. Problems with key components in newer turbine models without long track records could result in unexpected availability losses, increased and unbudgeted maintenance and repair costs, and lack of electric production affecting revenue generations. Wind energy projects typically consist of many WTGs of one particular make and model. Therefore, any failure of a key component could result in serial failures of such component throughout the wind energy project, resulting in significantly diminished revenues and materially increased maintenance and repair costs.

- *Dependence on Governmental Policies* - The wind energy industry is highly dependent upon governmental policies and laws enacted to stimulate growth of clean renewable energy through tax credits and other incentive plans, including mandatory purchasing requirements by local utilities of renewable energy, including wind energy. While the trend worldwide is to increase the use of renewable energy sources, there is no assurance that any particular governmental policy or tax credit or incentive program will be continued in any jurisdiction where Catamount conducts business.

Credit Risk Recent events including uncertainties concerning operations of wholesale markets and demise of major wholesale power marketing companies have increased credit exposure in the energy industry, most notably for unregulated energy companies. Obtaining or renewing corporate credit facilities is challenging and there is no guarantee credit will either be extended or renewed. In December 2002, Catamount extended its corporate credit facility to November 2004. In February 2004, Catamount notified the lender of its intent to terminate the credit facility. The termination is effective 90 days after notification to the lender. Catamount is currently soliciting proposals from selected financial institutions for corporate and/or development credit facilities that will meet its business needs. Catamount cannot predict whether it will be able to ultimately solicit and enter into an appropriately priced corporate and/or development credit facility.

Capital Requirements Catamount will require additional capital to pursue its business plan. Catamount is seeking investors and partners to co-invest in the development, ownership and acquisition of projects. There can be no assurance that Catamount will be successful in securing a partner or obtaining additional funding from the Company.

DISCONTINUED OPERATIONS

On January 1, 2004, Connecticut Valley completed the sale of substantially all of its plant assets and its franchise to PSNH. The sale resolved all Connecticut Valley restructuring litigation in New Hampshire and our stranded cost litigation at FERC. See FERC Exit Fee Proceedings below for additional information.

On January 1, 2004, PSNH paid Connecticut Valley about $30 million, with $9 million of that amount representing the net book value of its plant assets plus certain other adjustments, plus $21 million as provided in the agreements under which the sale was structured. In return, PSNH acquired Connecticut Valley's poles, wires, substations and other facilities, and several independent power obligations, including the Wheelabrator contract.

The sale resulted in a net gain of approximately $5 million to $7 million which will be recorded in the first quarter of 2004. The gain, net of reserves, is related to the difference between expected sales revenue for the power that we formerly sold to Connecticut Valley and estimated sales revenue at market rates, for the years 2004 through 2015. This represents the estimated life of the power contracts that were in place to source the wholesale power contract between the Company and Connecticut Valley. We will evaluate a long-term sale of the majority of power previously sold to Connecticut Valley to limit future market price variability.

The assets and liabilities of Connecticut Valley are classified as held for sale on the accompanying Consolidated Balance Sheets, in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, ("SFAS No. 144") and its results of operations are reported as discontinued operations for all periods presented in the accompanying Consolidated Income Statements. For presentation purposes, certain of our common corporate costs, which were previously allocated to Connecticut Valley, have been reallocated back to continuing operations to reflect the impact of the sale on continuing operations. These common costs amounted to about $1.3 million in 2003, $1.4 million in 2002 and $1.2 million in 2001, on an after-tax basis. We began to present Connecticut Valley as discontinued operations in the second quarter of 2003 based on the NHPUC's approval of the sale. Previously, Connecticut Valley was reported as a separate segment.

As a wholly owned subsidiary of the Company, Connecticut Valley's results of operations may not be representative of a stand-alone company. Summarized financial information related to Connecticut Valley, including the reallocation of certain corporate common costs, reflecting Management's best estimate of impacts of the Connecticut Valley sale, are shown in the tables below.

Summarized results of operations of the discontinued operations are as follows (dollars in thousands):

	December 31		
	2003	2002	2001
Operating revenues	**$19,728**	$20,242	$20,738
Operating expenses			
Purchased power	**14,725**	15,283	15,201
Other operating expenses	**2,049**	1,989	2,038
Income tax expense	**1,232**	1,224	1,289
Total operating expenses	**18,006**	18,496	18,528
Operating income	**1,722**	1,746	2,210
Other income (expense), net	**(276)**	(203)	(557)
Net income from discontinued operations, net of taxes	**$1,446**	$1,543	$1,653

The major classes of Connecticut Valley's assets and liabilities reported as held for sale on the Consolidated Balance Sheets are as follows (dollars in thousands):

	December 31	
	2003	2002
Assets		
Net utility plant	**$9,251**	$9,164
Other current assets	**41**	78
Total assets held for sale	**$9,292**	$9,242
Liabilities		
Accounts payable	**$1,749**	$2,237
Short-term debt (a)	**3,750**	3,750
Total liabilities of assets held for sale	**$5,499**	$5,987

(a) Related to a Note Payable to the Company and reported as Notes Receivable on the Consolidated Balance Sheets. The Note was paid on January 1, 2004.

FERC Exit Fee Proceedings

The Company's stranded cost litigation at FERC was related to its June 1997 request for FERC approval of a transmission rate surcharge to recover stranded costs if Connecticut Valley canceled its wholesale power contract with the Company due to the NHPUC's February 1997 Order in which it told Connecticut Valley to stop buying power from the Company. In December 1997, FERC rejected the proposal, but said it would consider an exit fee if the contract was canceled. A rehearing motion was denied. We applied for an exit fee totaling $44.9 million as of December 31, 1997.

In October 2002, the Company and NHPUC asked FERC to withhold its final exit fee order so the parties could continue to negotiate a settlement. In October 2003, FERC approved termination of the wholesale power contract and related exit fee proceedings upon completion of the sale. The sale of Connecticut Valley's plant assets and franchise to PSNH, and Connecticut Valley's $21 million payment to the Company to terminate the wholesale power contract resolved this FERC litigation.

Wheelabrator Power Contract Connecticut Valley purchased power from several independent power producers, which own qualifying facilities as defined by the Public Utility Regulatory Policies Act of 1978. In 2003 Connecticut Valley bought 38,700 mWh under long-term contracts with these facilities, 94 percent from Wheelabrator Claremont Company, L.P., ("Wheelabrator") which owns a trash-burning generating facility. Connecticut Valley had filed a complaint with FERC related to its concern that Wheelabrator had not been a qualifying facility since it began operation. FERC denied that complaint and later denied an appeal, so Connecticut Valley sought relief from the NHPUC. In April 2002 Connecticut Valley and other parties submitted a settlement to the NHPUC.

As a result of the January 1, 2004 sale described above, PSNH acquired Connecticut Valley's independent power obligations, including the Wheelabrator contract, thus resolving this issue.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2003, we had cash and cash equivalents of $58 million and working capital of $70 million. During 2003 cash and cash equivalents increased $10 million, reflecting net cash provided by operating activities of $46 million. Net cash used by investing activities amounted to $7.9 million mostly for construction expenditures, partially offset by the Vermont Yankee sale proceeds received in 2003. Net cash used in financing activities was $27.4 million, mainly related to retirement of long-term debt and dividends paid on common and preferred stock. We also used $12.6 million of restricted cash to reduce non-utility long-term debt and had restricted cash of $2 million related to our redeemable preferred stock that was paid in January 2004.

At December 31, 2002, we had cash and cash equivalents of $48 million and working capital of $51 million. We ended 2001 with $45 million in cash and cash equivalents and $51 million in working capital. During 2002 cash and cash equivalents increased $2 million, reflecting net cash provided by operations of $43 million and net cash used by investing activities of $1.4 million, representing proceeds from sales of non-utility assets, offset by construction expenditures. Net cash used in financing activities was $38.4 million mainly for retirement of long-term debt and preferred stock, and dividends paid on common and preferred stock. We also had restricted cash of $12.6 million related to scheduled retirement of non-utility long-term debt in 2003.

In the fourth quarter of 2003, we received $14.3 million related to the July 2002 sale of the Vermont Yankee nuclear power plant. On January 1, 2004, we received about $30 million related to the sale of Connecticut Valley's plant assets and franchise. We are currently considering investment alternatives for these cash proceeds. One such opportunity would be to increase our equity ownership in Vermont Electric Power Corporation, Inc. ("VELCO") from 10 percent up to 25 percent, and participate in its planned transmission upgrades, with construction scheduled to begin in late 2004 and extending through 2007. Our current common stock ownership percentage in VELCO is 50.5 percent. While Catamount has sufficient cash flow to cover its ongoing operating expenses, additional project investments will require financing or additional funding on the Company's part. Catamount is also seeking investors and partners to co-invest in the development, ownership and acquisition of projects.

We believe that cash on hand and cash flow from operations will be sufficient to fund our business for the foreseeable future. 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, and increases in net power costs largely due to lower-than-anticipated margins on sales revenue from excess power.

Capital Commitments and Contractual Obligations

The Vermont utility is a capital intensive operation, as it requires annual construction expenditures to maintain the distribution system. Our five-year capital expenditure plan is expected to range from $85 million to $95 million between 2004 and 2008.

Our significant contractual obligations as of December 31, 2003 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 - utility	$126.8	$75.0	-	$3.0	$48.8
Long-term Debt - non-utility	2.7	2.7	-	-	-
Redeemable Preferred Stock	10.0	1.0	$2.0	2.0	5.0
Purchased Power Contracts (a)	1,450.9	139.8	279.2	281.9	750.0
Capital Lease	11.8	1.1	2.2	1.8	6.7
Total Contractual Obligations	$1,602.2	$219.6	$283.4	$288.7	$810.5

(a) Includes power contract commitments with Hydro-Quebec, Vermont Yankee and various independent power producers. The costs associated with these obligations are currently being recovered in rates. See Power Supply Matters below for more information related to these contracts.

Financing/Credit Ratings/Capitalization

Utility Total utility long-term debt maturities and sinking fund requirements at December 31, 2003, amounted to $75 million related to our Second Mortgage Bonds, which mature on August 1, 2004. We are considering alternative refinancing arrangements. Currently, we intend to and have the ability to refinance the $75 million at maturity. No payments are due on long-term debt for 2005 through 2007. Substantially all of the our utility property and plant is subject to liens under the First and Second Mortgage Bonds.

We have $16.9 million of letters of credit expiring on November 30, 2004. These letters of credit support three series of Industrial Development/Pollution Control Bonds, totaling $16.3 million, and are secured by a first mortgage lien on the same collateral supporting our First Mortgage Bonds.

At December 31, 2003, we were in compliance with all debt covenants related to our various debt agreements; these agreements contain financial and non-financial covenants.

Non-Utility Catamount has a $25 million revolving credit/term loan facility and letters of credit, with $2.5 million outstanding at December 31, 2003. The facility expired on November 12, 2002 and on December 31, 2002, Catamount and its lender entered into the First Amendment to the facility that, among other things, extended the revolver facility for two more years. Under the two-year extension, Catamount can borrow against new operating projects subject to terms and conditions of the facility. The outstanding revolver loans were converted to amortizing loans on a two-year term-out schedule. The interest rate is variable, prime-based. Catamount's assets secure the facility. Catamount's long-term debt maturities, including its office building mortgage, total $2.7 million for 2004. Catamount's long-term debt contains financial and non-financial covenants. At December 31, 2003, Catamount was in compliance with all covenants under the credit facility.

In January 2004, Catamount paid off the outstanding $2.5 million on the term loan and in February 2004 Catamount notified the lender of its intent to terminate the credit facility. The termination is effective 90 days after notification to the lender. Catamount is now soliciting proposals from selected financial institutions for corporate and/or development credit facilities that will meet its business needs. Catamount cannot predict whether it will be able to ultimately solicit and enter into an appropriately priced corporate and/or development credit facility. The office building mortgage matures on April 15, 2004 and Catamount expects to pay the outstanding balance in full.

Credit Ratings On August 12, 2003, Standard & Poor's ("S&P") affirmed our corporate credit rating at 'BBB-', and reported the rating outlook as stable. S&P indicated that the affirmation was based upon an improving regulatory environment, a diverse customer mix, stable demand growth and low operating risk. S&P's stable outlook was based upon the Company's stable utility segment that should allow the Company to preserve its financial profile.

On September 10, 2003, Fitch IBCA ("Fitch") upgraded our first mortgage bond rating to 'BBB+' from 'BBB' and second mortgage bond rating to 'BBB' from 'BBB-'. Fitch also affirmed our preferred stock rating at 'BB+'and reported the rating outlook as stable. Fitch indicated that the higher ratings reflect the Company's strengthening credit measures and lower business risk related to the 2001 rate order, which provided full recovery of Hydro-Quebec purchased power agreement costs. Another factor was the sale of Vermont Yankee, eliminating the Company's nuclear operating risk.

Credit ratings should not be considered a recommendation to purchase stock. Current credit ratings are as follows:

	Standard & Poor's (1)	Fitch (1)
Corporate Credit Rating	BBB-	N/A
First Mortgage Bonds	BBB+	BBB+
Second Mortgage Bonds	BBB-	BBB
Preferred Stock	BB	BB+

(1) Outlook: Stable

Capitalization Our capitalization for the past three years was as follows:

	Amount (in millions)			Percent		
	2003	2002	2001	**2003**	2002	2001
Common stock equity	**$211**	$198	$183	**57%**	51%	47%
Preferred stock	**18**	18	24	**5**	5	6
Long-term debt	**129**	159	167	**35**	41	43
Capital lease obligations	**12**	12	13	**3**	3	4
	$370	$387	$387	**100%**	100%	100%

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our financial statements are prepared in accordance with GAAP, requiring us to make estimates and judgments that affect reported amounts of assets and liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements. Our most critical accounting policies are described below.

Regulation We prepare our financial statements in accordance with SFAS No. 71 for our regulated Vermont service territory and FERC-regulated wholesale business. We are regulated by the PSB, the NHPUC, the Connecticut Department of Public Utility and Control and the FERC, with respect to rates charged for service, accounting, financing and other matters pertaining to regulated operations. Under SFAS No. 71, we account for certain transactions in accordance with permitted regulatory treatment, as such, 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. In order for a company to report under SFAS No. 71, the company's 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 our regulated operations. Criteria that could give rise to the discontinuance of SFAS No. 71 include: 1) increasing competition that restricts the 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. We periodically review these criteria to ensure that the continuing application of SFAS No. 71 is appropriate. If we determine the Company no longer meets the criteria under SFAS No. 71, the accounting impact would be an extraordinary charge to operations of about $41.8 million on a pre-tax basis as of December 31, 2003, assuming no stranded cost recovery would be allowed through a rate mechanism. Based on a current evaluation of the factors and conditions expected to impact future cost recovery, we believe future recovery of our regulatory assets in the State of Vermont and State of New Hampshire for our retail and wholesale businesses is probable.

Discontinued Operations The assets and liabilities of Connecticut Valley are classified as held for sale in the Consolidated Balance Sheets in accordance with SFAS No. 144. In addition, as required by SFAS No. 144, the results of operations related to Connecticut Valley are reported as discontinued operations, and prior periods have been restated to conform to this presentation. For presentation purposes, certain of the Company's common corporate costs, which were previously allocated to Connecticut Valley, have been reallocated back to continuing operations to reflect the sale's impact on continuing operations. These common costs amounted to about $1.3 million in 2003, $1.4 million in 2002 and $1.2 million in 2001, on an after-tax basis. We began to present Connecticut Valley as discontinued operations in the second quarter of 2003 based on the NHPUC's approval of the sale of Connecticut Valley's plant assets and franchise to PSNH. Prior to the second quarter of 2003, Connecticut Valley was reported as a separate segment.

Unregulated Business Results of operations of our unregulated subsidiaries are included in the Other Income and Deductions section of the Consolidated Statements of Income. Catamount's policy is to expense all screening, feasibility and development expenditures associated with investments in new projects. Catamount's project costs incurred subsequent to obtaining financial viability are recognized as assets subject to depreciation or amortization. Project viability is obtained when it becomes probable that costs incurred will generate future economic benefits sufficient to recover these costs.

Catamount evaluates the carrying value of its investments on a quarterly basis or when events and circumstances warrant. The carrying value is considered impaired when the anticipated undiscounted cash flow is less than the carrying value of each investment. In that event, a loss is recognized based on the amount by which the carrying value exceeds the fair value of the investment. In 2003, Catamount determined that its investments in Rupert and Glenns Ferry were impaired by amounts that were not significant. Catamount recorded after-tax asset impairment charges of $2.1 million in 2002 and $9.8 million in 2001, related to certain of its investments. These asset impairments were based on bids received from third parties for sale of certain investments or the projects' financial condition. See Diversification below for additional information.

Revenues Electricity sales to customers are based on monthly meter readings. Estimated unbilled revenues are recorded at the end of each monthly accounting period. In order to determine unbilled revenues, the Company makes various estimates including 1) energy generated, purchased and resold, 2) losses of energy over transmission and distribution lines, 3) kilowatt-hour usage by retail customer mix - residential, commercial and industrial, and 4) average retail customer pricing rates.

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 it is more likely than not such tax assets will be unrealized. In the third quarter of 2003, the Company reduced certain income tax valuation allowances at Catamount by about $2.3 million, reflecting Management's best estimate that deferred income taxes for certain previously recorded equity losses will be realized. See Income Tax Issues below for additional information.

Decommissioning Cost Estimates Accounting for decommissioning costs of nuclear power plants involves significant estimates related to decommissioning costs to be incurred many years in the future. Primary drivers of changes to these estimates include, but are not limited to, increases in projected costs of spent fuel storage, security and liability and property insurance. We own, through equity investments, 2 percent of Maine Yankee, 2 percent of Connecticut Yankee and 3.5 percent of Yankee Atomic. All three plants are completely shut down and are conducting decommissioning activities. We are responsible for paying our equity ownership percentage of decommissioning costs and all other costs for these plants.

As of December 31, 2003, based on the most recent estimates provided, our share of remaining costs to decommission these nuclear units is about $7.4 million for Maine Yankee, $13.3 million for Connecticut Yankee and $7.5 million for Yankee Atomic. These estimates are recorded in the accompanying Consolidated Balance Sheets as nuclear decommissioning liabilities (current and non-current) with a corresponding regulatory asset or other deferred charge. We will adjust associated regulatory assets, other deferred charges and nuclear decommissioning liabilities when revised estimates are provided.

Based on the current regulatory process, we believe our proportionate shares of Maine Yankee, Connecticut Yankee and Yankee Atomic decommissioning costs will be recovered through rates. See Power Supply Matters - Nuclear Generating Companies below for more information.

We are also responsible for our 1.7303 joint-ownership percentage of Millstone Unit #3 decommissioning costs. Our contributions to the Millstone trust funds have been suspended based on the lead owner's representation to various regulatory bodies that the Trust Fund, for its share of the plant, exceeded the Nuclear Regulatory Commission's minimum calculation required. We could choose to renew funding at our discretion as long as the minimum requirement is met or exceeded. Currently, we are recovering these costs in rates. Prior to January 1, 2003, these amounts were applied to reduce certain regulatory assets. Since January 1, 2003, funds collected through retail rates are being recorded as a regulatory liability, to be addressed in our next rate proceeding.

Pension and Postretirement Benefits We record pension and other postretirement benefit costs in accordance with SFAS No. 87, *Employers' Accounting for Pensions*, and SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions.* Under these accounting standards, 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 is a list of the primary assumptions, which are reviewed annually, for 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. As of September 30, 2003, the discount rate was decreased from 6.5 percent to 6 percent, in light of long-term interest rates remaining at historically low levels.

- Expected Return on Plan Assets ("ROA") - We project the future ROA based principally on historical returns by asset category and expectations for future returns, 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, 2002, the ROA changed from 8.5 percent to 8.25 percent. This rate was used to determine the annual expense for 2003 and the same rate will be used to determine the 2004 expense.

- Rate of Compensation Increase - We project employees' annual pay increases, which are used to project employees' pension benefits at retirement. As of September 30, 2003, the rate of compensation increase was changed from 4 percent to 3.75 percent based on lower than previously projected trends in cost-of-living increases.

- Health Care Cost Trend - We project expected increases in the cost of health care. For measurement purposes, we assumed a 12 percent annual rate of increase in the per capita cost of covered health care benefits for pre-65 claims, and an 11.5 percent increase for post-65 claims, for fiscal 2004. These assumptions were based on expected higher health care costs.

- Amortization of Gains/(Losses) - We can select the method by which gains or losses are recognized in financial results. These gains or losses are created when actual results differ from estimated results based on the above assumptions. We recognize these gains and losses ratably over a five-year period.

The market value of pension plan trust assets was affected by sharp declines in the capital markets in 2001 and 2002, while favorable market returns in 2003, of about $12.1 million, helped to partially offset the market value decrease. Annual pension cost increased by $1.7 million for 2003 of which $1.4 million is reflected in results of operations and $0.3 million was allocated to accounts which are capitalized for accounting purposes.

Pension costs and cash funding requirements are expected to increase in future years. As of December 31, 2003, the market value of pension plan trust assets was $61.3 million, including $42.5 million in marketable equity securities and $18.8 million in debt securities. Pension plan trust assets were $55.9 million at December 31, 2002, including $34.8 million in marketable equity securities and $21.1 million in debt securities.

Postretirement costs also increased by $0.6 million for 2003 due to higher-than-expected medical claims experience. Of that amount, $0.4 million is reflected in results of operations and $0.2 million was allocated to accounts which are capitalized for accounting purposes.

See Note 10 to the Consolidated Financial Statements for additional information related to Pension and Postretirement Benefits.

RESULTS OF OPERATIONS

The following sections of Management's Discussion and Analysis compare the results of operations for each of the three years ended December 31, 2003, 2002 and 2001 and should be read in conjunction with the consolidated financial statements and accompanying notes included elsewhere in this report.

Consolidated Summary: Consolidated 2003 earnings were $19.8 million, or $1.57 per basic and $1.53 per diluted share of common stock. Consolidated 2002 earnings were $19.8 million, or $1.56 per basic and $1.53 per diluted share of common stock, while 2001 earnings were $2.4 million, or $.06 per basic and diluted share of common stock.

Discontinued operations of Connecticut Valley for 2003 contributed $1.4 million, or $.12 per basic and diluted share of common stock. It contributed $1.5 million, or $.13 per basic and diluted share of common stock, in 2002 and $1.7 million, or $.14 per basic and diluted share of common stock, in 2001. Connecticut Valley's plant assets and franchise were sold to PSNH on January 1, 2004.

The Vermont utility earnings were above the allowed rate of return on common equity of 11 percent for the 12 months ended December 31, 2003, resulting in a $1.5 million, after-tax, reduction of the Vermont utility's earnings, to stay below the mandated earnings cap. Similarly, in 2002 the Vermont utility earnings were reduced by about $0.4 million, after-tax. We recorded related pre-tax regulatory liabilities amounting to about $2.5 million in 2003 and $0.7 million in 2002, which are expected to be used to decrease deferred charges on the balance sheet at December 31, 2003.

2003 vs. 2002:

The following table provides a reconciliation of 2003 and 2002 diluted earnings per share:

2002 Earnings per diluted share	$1.53
Year-over-Year Effects on Earnings:	
▪ Federal income tax provision in 2003	$.19
▪ Higher retail sales and other operating revenue	.17
▪ Change in cash surrender value of insurance policies	.16
▪ Lower other expenses	.10
▪ Eversant income in 2003 versus a loss in 2002	.08
▪ Vermont Yankee transaction cost in 2002	.05
▪ Discontinued operations	(.01)
▪ Reversal of environmental reserve in 2002	(.09)
▪ Higher net power costs	(.14)
▪ Lower equity in earnings	(.16)
▪ Catamount losses (excluding 2003 tax benefit) versus earnings in 2002	(.26)
▪ Vermont utility mandated earnings cap	(.09)
Sub-total	.00
2003 Earnings per diluted share	**$1.53**

In summary, 2003 retail sales revenue increased $3.2 million over 2002, primarily due to increased retail mWh sales from colder winter months in the first quarter of 2003. Net power costs in 2003 increased about $3 million compared to 2002. Of that amount $2.2 million was related to state tax benefits realized by Vermont Yankee in 2002 as a result of the sale of the plant. These tax benefits were passed through to the plant owners, partly in the form of lower purchased power billings from Vermont Yankee, which reduced 2002 purchased power expense. We discuss operating revenues and net purchased power and production fuel costs in more detail below.

Other factors affecting 2003 earnings compared to 2002 included lower transmissions costs, lower interest expense, internal cost cutting efforts, lower bad debt reserves in 2003 compared to 2002 due to several customer bankruptcies in 2002, and the favorable impact of an increase in the cash surrender value of certain life insurance policies due to financial market results. Offsetting these favorable items were increased employee-related costs, lower equity in earnings from Vermont Yankee due to the July 2002 sale of the plant, including Vermont Yankee's state tax benefits, and the Vermont utility mandated earnings cap described above. Earnings in 2002 also included a reversal of environmental reserves and a one-time transaction cost related to the sale of Vermont Yankee, with no comparable items in 2003.

In the third quarter of 2003, the consolidated federal income tax provision reflected a benefit of about $2.3 million related to capital gain treatment on the proposed sale of Connecticut Valley (which closed January 1, 2004). The capital gain treatment allowed for a reduction of certain income tax valuation allowances at Catamount, reflecting Management's best estimate that deferred income taxes for certain previously recorded equity losses will be realized. See Income Tax Issues below.

Excluding these income tax benefits, Catamount recorded losses of about $1.6 million in 2003, primarily related to lower equity earnings and lower project development revenue, offset by lower interest expense due to lower debt. This compares to earnings of about $1.5 million in 2002, primarily related to higher equity earnings from several of its investments and realized development revenue upon the sale of another investment, offset by asset impairment charges taken for its investments that were sold in the fourth quarter of 2002.

Eversant recorded earnings of $0.5 million in 2003 compared to losses of $0.5 million in 2002, resulting from discontinuing its efforts to pursue unregulated business opportunities, partially offset by the reversal of an IRS interest expense accrual in 2002, previously recorded in the fourth quarter of 2001.

2002 vs. 2001:

The following table provides a reconciliation of 2002 and 2001 diluted earnings per share:

	2002 vs. 2001
2001 Earnings per diluted share	$.06
Year-over-Year Effects on Earnings:	
▪ Higher retail sales and other operating revenue	.43
▪ Eversant lower losses	.14
▪ Higher equity in earnings	.11
▪ Reversal of environmental reserve in 2002	.09
▪ Discontinued operations	(.01)
▪ Vermont utility mandated earnings cap in 2002	(.03)
▪ Vermont Yankee transaction cost in 2002	(.05)
▪ Higher other expenses	(.22)
▪ Higher net power costs	(.33)
▪ June 2001 Vermont rate case settlement	.46
▪ Catamount earnings versus losses in 2001	.88
Sub-total	1.47
2002 Earnings per diluted share	**$1.53**

In summary, 2002 retail sales revenue increased $7.7 million from higher average retail rates due to a 3.95 percent retail rate increase beginning July 1, 2001, and increased mWh sales. Net power costs increased $6.4 million related to a number of factors including lower resale sales revenue, increased purchases to support higher retail sales, and several one-time items in 2001 with no comparable items in 2002. We discuss operating revenues and net purchased power and production fuel costs in more detail below.

Other factors affecting 2002 results compared to 2001 included higher other operating revenue related to the sale of non-firm transmission under our open access transmission tariff, offset by higher operating and other costs. In 2001, the Company wrote off $9 million, pre-tax, of certain regulatory assets related to its July 2001 rate case settlement. There was no such comparable item in 2002.

Catamount's earnings were $1.5 million in 2002 versus losses of $8.7 million in 2001. Compared to 2001, its 2002 earnings reflected higher equity in earnings from several of its investments and realized development revenue upon the sale of one of its investments in the fourth quarter of 2002, offset by after-tax asset impairment charges of $2.1 million taken for its investments that were sold in the fourth quarter of 2002. In 2001, Catamount's after-tax asset impairment charges amounted to about $9.8 million related to several of its investments. See Diversification below for a more detailed discussion of Catamount's investments and these after-tax asset impairment charges. Eversant's net losses were $1.6 million lower in 2002, primarily related to a 2001 write down of its investment in the Home Service Store, Inc. ("HSS") to fair value. See Diversification below for a more detailed discussion of Eversant.

CONSOLIDATED INCOME STATEMENT DISCUSSION

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

Operating revenues: The majority of our operating revenues are generated through retail sales from our regulated Vermont utility business. Other resale sales are related to the sale of excess power from our owned and purchased power supply portfolio. These resale sales are also discussed in Net Purchased Power and Production Fuel Costs below. Operating revenues and related mWh sales for 2003, 2002 and 2001 are summarized below:

	mWh Sales			Revenues (000's)		
Retail sales:	**2003**	2002	2001	**2003**	2002	2001
Residential	**948,278**	915,030	897,220	**$125,402**	$121,420	$116,719
Commercial	**848,413**	858,537	853,242	**102,758**	103,073	100,802
Industrial	**396,081**	407,335	405,099	**33,716**	34,206	33,476
Other retail	**5,391**	5,441	5,497	**1,599**	1,608	1,597
Total retail sales	**2,198,163**	2,186,343	2,161,058	**263,475**	260,307	252,594
Resale sales:						
Firm (1)	**5,002**	2,392	1,927	**179**	137	139
Entitlement	**-**	-	165,184	**-**	-	7,303
RS-2 power contract (2)	**122,685**	124,483	130,555	**10,409**	10,948	10,935
Other	**567,921**	442,187	406,694	**24,587**	15,806	16,153
Total resale sales	**695,608**	569,062	704,360	**35,175**	26,891	34,530
Other revenues	**-**	-	-	**7,364**	7,192	5,777
Total	**2,893,771**	2,755,405	2,865,418	**$306,014**	$294,390	$292,901

(1) Firm sales and are based on FERC filed tariffs.

(2) RS-2 power contract is the wholesale power contract between the Company and Connecticut Valley. The Company and Connecticut Valley terminated this contract upon completion of the sale of Connecticut Valley's plant assets and franchise to PSNH on January 1, 2004. See Discontinued Operations above.

Differences in Operating revenues were due to changes in the following:

Change in Operating Revenues	**2003 vs. 2002**	2002 vs. 2001
Retail revenues:		
Change in mWh volume	$2,237	$3,111
Change in price (customer mix)	931	4,602
Subtotal	3,168	7,713
Firm resale sales	42	(2)
RS-2 power contract	(539)	13
Entitlement sales	-	(7,303)
Other resale sales	8,781	(347)
Other revenues	172	1,415
Increase in Operating Revenues	$11,624	$1,489

2003 vs. 2002:

Operating revenues increased $11.6 million in 2003 as a result of the following factors:

- Retail sales increased $3.2 million primarily due to an 11,820 mWh increase in sales volume. These sales are affected by weather and economic conditions. In 2003, colder weather in the first quarter increased residential sales volume, while relatively weak economic conditions decreased sales volume for our Commercial and Industrial customers.
- Other resale sales increased $8.8 million due to higher rates for contract sales and wholesale market prices in ISO-New England, and more power available for resale in 2003. The reasons we had more mWh available for resale are described in more detail in Net Purchased Power and Production Fuel Costs below.
- Sales to Connecticut Valley under the RS-2 power contract decreased $0.5 million due to lower volume and lower unit costs under the contract.

2002 vs. 2001:

Operating revenues increased $1.5 million in 2002 due to the following factors:

- Retail sales increased $7.7 million mostly from higher average retail rates due to a 3.95 percent retail rate increase beginning July 1, 2001, and a 1.2 percent increase in mWh sales.
- Entitlement sales decreased $7.3 million due to the October 2001 completion of a five-year power contract in which we sold 15 percent of our share of Vermont Yankee output at full cost.

- Other resale sales decreased $0.3 million primarily due to lower ISO-New England market prices, offset by an 8.7 percent increase in mWh sales for the same period. The reasons we had more mWh available for resale are described in more detail in Net Purchased Power and Production Fuel Costs below.
- Other revenues increased $1.4 million primarily due to the sale of non-firm transmission under our open-access transmission tariff.

Net Purchased Power and Production Fuel Costs: The cost components of net purchased power and production fuel for 2003, 2002 and 2001 are summarized below. These costs are shown net of entitlement and other resale sales revenue to reflect net power costs to support our load requirements. Other resale sales are related to sales of excess power from our owned and purchased power supply portfolio. The amount of related revenue is dependent on contract or ISO-New England market prices at the time of the sales. Also see Power Supply Matters below for a detailed discussion of our power supply sources, power management, purchased power commitments and nuclear investments.

(dollars in thousands)	2003		2002		2001	
	mWh	Amount	mWh	Amount	mWh	Amount
Purchased power:						
Capacity		$41,599		$69,528		$86,121
Energy	2,649,833	111,396	2,587,859	72,902	2,745,553	57,274
Total purchased power		152,995		142,430		143,395
Production fuel	412,638	3,964	378,232	2,732	320,022	2,995
Total purchased power and production fuel		156,959		145,162		146,390
Less entitlement and other resale sales	567,921	24,587	442,187	15,806	571,878	23,456
Net purchased power and production fuel costs	2,494,550	$132,372	2,523,904	$129,356	2,493,697	$122,934

As shown in the table above, purchased energy increased significantly in 2003 versus 2002 and 2001, while purchased capacity decreased significantly over the same periods. This shift in purchased power cost structure is related to the July 31, 2002 sale of Vermont Yankee. We continue to purchase a similar share of plant output, but all purchases made under the purchased power agreement ("PPA") are recorded as energy purchases. The majority of these purchases were recorded as capacity purchases when we owned the plant.

In 2002, based on a PSB-approved accounting order, we deferred about $5.2 million of Vermont Yankee sale related costs including a portion of PPA costs that were higher than estimated costs had we continued to own and operate the plant for the full year. This brought our overall Vermont Yankee costs in line with those experienced in prior years.

2003 vs. 2002:

Net purchased power and production fuel costs increased about $3 million in 2003 as a result of the following factors:

- A $10.6 million increase in purchased power costs primarily due to:
  - An $11.6 million increase in Vermont Yankee related costs as a result of higher output from the plant in 2003 which increased purchases by about $8.2 million, and a $3.4 million net increase due to accounting for Vermont Yankee including the 2002 sale. The sale-related items included a $5.2 million deferral of energy costs as described above, and a $2.2 million reduction in 2002 power costs due to state tax benefits realized by Vermont Yankee that were passed on to the Vermont Yankee sponsors. These items were offset by a decrease of about $4 million due to the elimination of amortizations for Vermont Yankee nuclear refueling outages.
  - A $2 million increase in ISO-New England capacity charges due to credits we received in 2002 for our share of revenues from the ISO-New England capacity deficiency pool. We did not receive these credits in 2003.
  - A $1 million increase in purchases from independent power producers due to higher volume and rates.
  - A $1.7 million decrease in purchases from Hydro-Quebec due to fewer deliveries.
  - A $1.3 million decrease in short-term and spot energy purchases.
  - A $1 million decrease in installed capacity purchases due to lower rate and volume.
- An $8.8 million increase in other resale sales related to more mWh available for resale in 2003, at higher contract rates and higher wholesale market prices in New England. The higher contract rates were related to a forward sale in 2003 in which we sold about 306,000 mWh for the period February through December 2003. In 2002 most of our resale sales were at ISO-New England market prices. We had more mWh available for resale primarily due to increased output from Vermont Yankee and Millstone, as each plant was off-line for scheduled refueling and maintenance in 2002. Also Vermont Yankee had a second quarter 2002 unscheduled outage for fuel rod repairs.

- A $1.2 million increase in production fuel costs related to our joint-owned units. Wyman and McNeil generated more mWh in 2003 and at higher energy rates. Also, Millstone Unit #3 generated more mWh in 2003.

2002 vs. 2001:
Net purchased power and production fuel costs increased about $6.4 million in 2002 due to the following factors:
- Lower wholesale market prices in 2002 reduced revenue from resale sales by about $3.2 million. These resale sales offset the cost of power, so reduced revenue resulted in higher net power costs.
- Power requirements related to increased retail sales, losses, and capacity needs increased purchased power costs by about $1.1 million.
- Lower net Vermont Yankee costs of about $1.8 million related to the favorable impact of a $5.2 million deferral of energy costs as described above and the favorable impact of a $2.2 million reduction in purchased power expense due to state tax benefits realized by Vermont Yankee and passed through to the owners. Also, Vermont Yankee purchases increased by about $5.5 million in 2002 due to an 11.8 percent increase in our entitlement share of plant output beginning March 2002 based on negotiations with secondary purchasers. This also made available an additional 118,000 mWh.
- A $1.6 million decrease in ISO-New England capacity costs related to higher credits in 2002 for our share of the ISO-New England capacity deficiency pool.
- A $5.4 million unfavorable impact resulting from items in 2001 with no comparable items in 2002, including, 1) the June 2001 rate case settlement that ended Hydro-Quebec power cost disallowances, resulting in a $2.9 million reversal of a second-quarter 2001 accrual for under-recovery of power costs, and 2) a $2.5 million reversal of a December 2000 accrual for estimated costs for installed capacity in ISO-New England due to the resolution of a December 2000 FERC Order.

Operating Expenses: Operating expenses represent costs incurred to support our core business. These expenses, excluding purchased power and production fuel costs, are described below.

Production and Transmission: These are expenses primarily associated with generating electricity from our wholly and jointly owned units and transmission of electricity. Fuel-related costs are discussed in Net Purchased Power and Production Fuel Costs above. There was no significant variance in these expenses for 2003 versus 2002 or for 2002 versus 2001.

Other operation This is primarily related to operating activity such as customer accounting, customer service, administrative and general and other operating costs incurred to support our core business. These costs amounted to about $46.7 million in 2003, $43.5 million in 2002 and $42.8 million in 2001. The $3.2 million increase for 2003 versus 2002 and $0.7 million increase for 2002 versus 2001 are primarily related to the Vermont utility's mandated earnings cap, which resulted in a pre-tax expense of $2.5 million in 2003 and $0.7 million in 2002 to stay below the mandated earnings cap. We also recorded related pre-tax regulatory liabilities of about $2.5 million in 2003 and $0.7 million in 2002, which is expected to be used to decrease deferred debits on the balance sheet at December 31, 2003.

Other factors affecting 2003 versus 2002 included a $1.7 million reversal of environmental reserves in 2002, which results in an unfavorable variance when comparing 2003 versus 2002, and higher employee-related costs, offset by internal cost cutting efforts, and lower bad debt reserve adjustments in 2003 compared to 2002 due to several customer bankruptcies in 2002.

Maintenance This is primarily related to costs associated with maintaining our electric distribution system. There was no significant variance in these expenses for 2003 versus 2002 or 2002 versus 2001.

Depreciation We use the straight-line remaining-life method of depreciation. There was no significant variance for 2003 versus 2002 or for 2002 versus 2001.

Other taxes, principally property taxes This is primarily related to property taxes and payroll taxes. There was no significant variance in these expenses for 2003 versus 2002 or for 2002 versus 2001.

Taxes on Income Federal and state income taxes fluctuate with the level of pre-tax earnings in relation to permanent differences and changes in valuation allowances for the periods. See Income Tax Issues below.

Equity in earnings of affiliates: These are related to our investments in VELCO and Vermont Yankee. Equity in earnings of affiliates amounted to about $1.8 million in 2003, $3.9 million in 2002 and $2.7 million in 2001. The $2.1 million decrease for 2003 versus 2002 and $1.2 million increase for 2002 versus 2001 were primarily related to state tax benefits realized by Vermont Yankee in 2002 as a result of the sale of the plant. These tax benefits were passed through to the plant owners, partly in the form of higher equity in earnings, with the remaining through lower purchased power expense as described above. Additionally, the July 2002 sale of the Vermont Yankee plant has reduced our ongoing equity in earnings from that investment. See Power Contract Commitments - Vermont Yankee below for more detail.

Other income, net: These income items, net of deductions, are related to the non-operating activities of the utility business and the operating activities of our unregulated businesses. Other income, net amounted to about $2.7 million in 2003 and $1.6 million in 2002. In 2001 Other income, net amounted to a deduction of about $16.3 million. The year-over-year variances were as follows (dollars in millions):

	2003 vs. 2002	2002 vs. 2001
Utility Business		
Cash surrender value of life insurance policies	$1.9	$(0.4)
Interest and dividend income	0.3	(1.0)
Vermont rate case regulatory asset write-off in 2001	-	9.0
Vermont Yankee sale - one-time payment in 2002	1.0	(1.0)
Unregulated Businesses		
Catamount revenues and expenses	(7.3)	3.9
Catamount asset impairment charges in 2002	2.8	(2.8)
Catamount asset impairment charges in 2001	-	8.9
Eversant revenues and expenses	1.3	(0.2)
Eversant (HSS) write-down in 2001	-	2.0
Other *(various items)*	1.1	(0.5)
Total Variance	$1.1	$17.9

UtilityBusiness In 2003, the cash surrender value of certain life insurance policies increased significantly due to financial market results. This lowered life insurance expense in 2003. In 2002, we made a one-time payment of $1 million to the non-Vermont owners related to closing the Vermont Yankee sale. Also in 2001, we had to write off $9 million of certain regulatory assets as a result of our June 26, 2001 rate case settlement with the PSB.

Unregulated Businesses In 2003, Catamount net revenues and expenses decreased $7.3 million due to lower equity earnings from several of its investments and realized development revenue in 2002 upon the sale of one of its investments. Catamount also had pre-tax asset impairment charges of $2.8 million in 2002 and $8.9 million in 2001.

In 2003, Eversant net revenues and expenses, excluding interest, increased $1.3 million due to discontinuance of its efforts to pursue unregulated business opportunities. In 2001, Eversant had a $2 million write-down related to its investment in HSS. Catamount and Eversant are explained in more detail in Diversification below.

(Provision) benefit for income taxes: Federal and state income taxes fluctuate with the level of pre-tax earnings in relation to permanent differences and changes in valuation allowances for the periods. See Income Tax Issues below for more detail.

Interest on long-term debt: Interest expense on long-term debt includes the utility business and our unregulated businesses. In 2003 interest on long-term debt amounted to about $11.2 million in 2003, $12.5 million in 2002 and $12.8 million in 2001. For the utility business, interest expense decreased annually due to the retirement of first mortgage bonds in the amount of $10.5 million in 2003, $7 million in 2002 and $4 million in 2001. For our unregulated businesses, interest expense amounted to $0.5 million in 2003, $1.2 million in 2002 and $1 million in 2001, reflecting a reduction of Catamount's long-term debt beginning in early 2003.

Other interest expense: Other interest expense includes the utility business and our unregulated businesses. In 2003, Other interest expense amounted to about $0.5 million. Other interest in 2002 reflected a small amount of interest income. In 2001, Other interest expense amounted to about $1 million. The year-over-year variance is primarily related to Eversant's 2002 settlement of an IRS audit resulting in the reversal of a related interest expense accrual previously recorded in the fourth quarter of 2001.

Discontinued Operations: This represents results of operations related to Connecticut Valley, which is classified as held for sale. See discussion of Discontinued Operations above.

Dividends on preferred stock: Preferred stock dividends decreased by $0.3 million in 2003 and $0.2 million in 2002 due to lower outstanding preferred stock balances.

POWER SUPPLY MATTERS

Sources of Energy We purchase about 90 percent of our power under several contracts of varying duration. The remaining is supplied by our jointly and wholly owned generating facilities, and short-term purchases. Our power supply portfolio includes a mix of base load and schedulable resources to help cover peak load periods. A breakdown of energy sources is shown below:

	2003	2002	2001
Nuclear generating companies	50%	46%	43%
Canadian hydro contract	27	30	36
Company-owned hydro and thermal	6	6	4
Jointly owned units	8	7	6
Independent power producers	5	5	4
Other	4	6	7
	100%	100%	100%

Our joint-ownership interests include 1.7303 percent in Unit #3 of the Millstone Nuclear Power Station, 20 percent in Joseph C. McNeil, a 53-MW wood-, gas- and oil-fired unit, and 1.78 percent joint-ownership in Wyman #4, a 619-MW oil-fired unit. 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 73.6 MW.

We have a long-term power contract with Hydro-Quebec and a long-term power contract for purchase of about 35 percent of Vermont Yankee plant output. These contracts support about 90 percent of our total annual energy (mWh) purchases. We are required to purchase power from various Independent Power Producers ("IPPs") under long-term contracts. These contracts are discussed in more detail below.

Power Supply Management We engage in short-term purchases and sales in the wholesale markets administered by the New England Independent System Operator ("ISO-New England") and with other third parties, primarily in New England, to minimize net power costs and risks to our customers. Based on commitments and contracts, we expect that net purchased power and production fuel costs will average approximately $125 million to $136 million per year for the years 2004 through 2008. Our long-term power forecast reflects energy amounts excess to that required to meet load requirements; therefore net power costs are dependent, in part, upon wholesale power market prices. Additionally, the January 1, 2004, sale of Connecticut Valley's assets and termination of its power contract released an average of about 11 MW on-peak and 17 MW off-peak of our power supply mix for future disposition.

On an hourly basis, power is sold or bought through ISO-New England to balance our resource output and load requirements. From time to time, we enter into forward sale transactions in order to reduce volatility of our forecasted power costs. We may also enter into forward purchase transactions, when our forecasts reflect deficiencies such as scheduled refueling outages at Vermont Yankee. For the period February through December 2003, we sold about 306,000 mWh to a third party under a forward sale contract. In December 2003, we entered into a forward sale contract for about 148,400 mWh for the period January through March 2004, and a forward purchase contract for about 27,100 mWh for April 2004 in anticipation of a Vermont Yankee scheduled refueling outage. These forward transactions are in addition to our hourly purchases and sales with ISO-New England; however they decrease the volume of those hourly transactions.

We also continue to monitor, and adapt to, changes to New England wholesale power markets and open access transmission systems. Related to the wholesale power markets, in March 2003, ISO-New England implemented Standard Market Design ("SMD"), a significant step to restructuring the wholesale energy markets in the Northeast. The move to regional transmission organizations ("RTO") also continues. SMD has impacted wholesale power prices related to short-term sales and purchases as well as the costs of our own generation. Although we expect that the RTO will impact our transmission costs at some point, we are not able to predict the nature of that impact. Below is a brief discussion of SMD and RTO.

Standard Market Design

On March 1, 2003, ISO-New England moved to a new market structure referred to as SMD. Some of the market changes include:

- Energy pricing now includes the costs (or benefits) of transmission congestion and marginal losses experienced at each location within the region. This is known as locational marginal pricing. Previously, costs of congestion and average losses were spread across New England energy providers on a pro rata basis.
- Location-specific pricing, based on where Generators and load connect to the New England system. Generation is priced at specific location 'nodes' while load is priced by 'zones' (each state is a zone, except Massachusetts, which is comprised of three zones).
- Day-ahead and real-time energy markets, allowing participants to settle transactions involving load and generation in real-time or one day in advance.
- An auction-based system of Financial Transmission Rights ("FTR") allowing participants to hedge congestion risks. FTR holders are paid (or charged) the day-ahead congestion value of the transmission path for which they hold an FTR, while auction proceeds are distributed via Auction Revenue Rights to load entities that experience day-ahead congestion or companies that increase the capacity of the network.
- Increased ISO-New England financial assurance requirements for market participants, based on their credit ratings and financial conditions.

In general, we own or hold entitlements to generation that can be self-scheduled in the day-ahead or real-time market. We have been using the day-ahead market to clear the majority of our load and generation, including generation resources that we self-schedule, with any remaining resources and residual load settling in the real-time market.

At this time, much of the cost of New England's existing and new high-voltage transmission system (115 kV looped facilities) is shared by all New England utilities. VELCO is planning several significant upgrades, which have been approved by the New England Power Pool for shared cost treatment. Vermont has traditionally been a significantly higher than average transmission cost jurisdiction. The new approach is advantageous to the Company's cost and reliability in providing service to its customers because our load share is a small fraction of total New England load, and the facilities VELCO is planning improve both the reliability and efficiency (i.e., losses and congestion) of the transmission network. We will pay a share of such projects elsewhere in New England but the net economic effect is expected to be beneficial, and better reliability elsewhere in the region benefits Vermont's reliability because of the highly integrated nature of New England's high voltage network. However, the cost of other future transmission facilities that do not qualify for cost sharing will be charged only to the requesting entity and our share of such costs will be affected by FERC approved cost-allocation rulings contained in VELCO's and the Company's tariffs and agreements.

Regional Transmission Organizations ("RTO")

We operate our transmission system under an open-access tariff, pursuant to FERC Order No. 888. In 1999, FERC began work to amend regulations and facilitate formation of RTOs, and in 2001, FERC issued Order No. 2000 for that purpose. Since that time, we have participated in numerous related proceedings, including discussions to create an Open Access Transmission Tariff and Transmission Owners Agreement to govern the provision of transmission services.

In July 2002, FERC issued a Standard Market Design Notice of Proposed Rulemaking to establish nationwide rules for power markets and RTOs. The rulemaking was designed to separate governance and operation of the transmission system from generation companies and other market participants and facilitate power markets with common rules.

On October 31, 2003, ISO-New England and the transmission-owning entities in New England, including the Company, filed a joint proposal with FERC to create an RTO for New England. Certain transmission owners in New England also reached an agreement to submit (no later than February 1, 2004) a tariff, agreements and other documents to FERC to include costs associated with certain transmission facilities, commonly referred to as the Highgate Facilities, in region-wide rates as set forth in the proposal to create an RTO for New England. We have agreed to defer the FERC filing to allow time for the RTO stakeholders' review process and expect to file shortly after this process is concluded. We cannot predict the outcome of this matter or its impact to the Company.

Power Contract Commitments

Hydro-Quebec We are purchasing varying amounts of power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract through 2016 and related contracts negotiated between the Company and Hydro-Quebec.

These related contracts altered the terms and conditions of the original contract by reducing the overall power requirements and related costs. There are specific contractual provisions that provide that in the event any VJO member fails to meet its obligation under the contract with Hydro-Quebec, the remaining VJO participants, including the Company, must "step-up" to the defaulting party's share on a pro rata basis. As of December 31, 2003, our obligation is approximately 46 percent of the total VJO Power Contract through 2016, which translates to about $734 million, on a nominal basis, over the contract term. The average annual capacity that we will purchase from January 1, 2004 through October 31, 2012 is 144.2 MW, with lesser amounts purchased thereafter through October 31, 2016. See Note 13 to the Consolidated Financial Statements for further discussion of this contract.

In 2003, we purchased about $57.5 million of energy and related capacity under the existing contracts with Hydro-Quebec. Estimated purchases under these contracts based on a load factor of 65 percent for 2004 and 2005, and 75 percent for 2006 through 2008, are expected to be about $58.2 million in 2004, $61.4 million in 2005, $62.1 million in 2006, $62.5 million in 2007 and $63.3 million in 2008.

On January 30, 2004, Hydro-Quebec notified the VJO that it is not likely that Hydro-Quebec will reschedule deliveries of energy not delivered during the prior contract year (November 1, 2002 through October 31, 2003) due to interconnection deficiencies. At this time, we are working with Hydro-Quebec to minimize such interconnection deficiencies through various scheduling modifications and use of interconnection facilities. We are unable to predict how this might impact our 2004 net power costs; however, under the VJO contract, we are responsible for paying capacity costs, and any reduced deliveries would either result in purchases of energy through short-term purchases, or decreased resale sales.

Vermont Yankee We have a 35 percent entitlement in Vermont Yankee plant output sold by Entergy to Vermont Yankee, through a long-term power purchase contract with Vermont Yankee, and one remaining secondary purchaser continues to receive a small percentage of our entitlement, reducing our entitlement to about 34.83 percent. The long-term contracts between Vermont Yankee and the entitlement holders and between Vermont Yankee and Entergy became effective on July 31, 2002, the same day that the Vermont Yankee nuclear plant was sold to Entergy. We no longer bear the operating costs and risks associated with running the plant or the costs and risks associated with the eventual decommissioning of the plant. We are responsible for the purchase of replacement power to serve our load requirements when the plant is not operating due to scheduled or unscheduled outages.

The PPA through which Vermont Yankee purchases power from Entergy and in turn sells to its sponsors includes prices that generally range 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" that protects the Company and our power consumers if power market prices drop significantly. The low-market adjuster is a mechanism in which the PPA base contract price for each billing month is compared to a twelve-month average (ending in same billing month) of hourly market prices as defined in the PPA. If the twelve-month average market price is less than 95 percent of the base PPA contract price, then 105 percent of the twelve-month average market price will be used for the billing month. The low-market adjuster cannot exceed the base PPA contract price. If the market prices rise, however, contract prices are not adjusted upward. In addition to PPA charges, Vermont Yankee's billings to the sponsors include certain of its residual costs of service through a FERC tariff to the Vermont Yankee sponsors. The PPA is expected to result in decreased costs over the life of the PPA when compared to the projected cost of continued ownership of the plant.

In 2003, our Vermont Yankee purchases were about $65.2 million based on our entitlement share of plant output. Future purchases are expected to be $62.8 million in 2004, $57.7 million in 2005, $60.7 million in 2006, $57.9 million in 2007 and $59.2 million in 2008.

In 2003, Entergy sought PSB approval to increase generation at the Vermont Yankee plant by 110 megawatts. On November 5, 2003, the DPS announced that it had agreed to support Entergy's proposed uprate including Entergy's agreement to provide outage protection indemnification for the Company and Green Mountain Power in case the uprate causes temporary outages that require the Vermont utilities to buy higher-cost replacement power. The outage protection coverage will be in place for three years, during which there may be uprate-related outages. We have indemnification rights up to about $2.8 million. The agreement requires PSB approval, and hearings began in January 2004.

On February 10, 2004, Entergy notified us that it expects that the plant output will be reduced beginning after the April 2004 scheduled refueling outage, and continuing until Entergy receives Nuclear Regulatory Commission approval for the uprate, which is expected no earlier than November 2004. This will reduce our 182 MW entitlement by about 7 MW during this period. We cannot predict the outcome of this matter or how it might affect future operations of Vermont Yankee; but a decrease in the output of Vermont Yankee could have a material impact on us, given that our long-term contract for Vermont Yankee output provides a significant part of our power supply mix.

Independent Power Producers ("IPPs") We purchase power from a number of IPPs who own qualifying facilities under the Public Utility Regulatory Policies Act of 1978. These qualifying facilities produce energy using hydroelectric, biomass and refuse-burning generation. The majority of these purchases are made from a state-appointed purchasing agent ("VEPPI") that purchases and redistributes the power to all Vermont utilities. In 2003, we received 164,918 mWh under these long-term contracts, including 142,968 mWh received through VEPPI. These IPP purchases account for 6.2 percent of our total mWh purchased and 11 percent of purchased power costs. Estimated purchases from IPPs are expected to be $18.8 million in 2004, $18.8 million in 2005, $18.5 million in 2006, $19.2 million in 2007 and $19.8 million in 2008. These amounts reflect annual savings credits of about $0.6 million related to the IPP settlement that is described in Note 13 to the Consolidated Financial Statements.

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 73.6 MW.

We are in the process of relicensing or preparing to license six separate hydroelectric 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 our total hydroelectric nameplate capacity. The FERC is expected to impose conditions designed to address impacts on fish and the environment. We cannot predict the specific impact of any conditions, but capital expenditures and operating costs are expected to increase in the short term and net generation from these projects will likely decrease.

Peterson Dam We have worked with environmental groups and the State of Vermont since 1998 to develop a plan to relicense Peterson Dam, a 6.35-MW hydroelectric station on the Lamoille River. The Vermont Natural Resources Council ("VNRC") and others proposed removal of the 1948 facility, which produces power to energize about 3,000 homes per year. In April 2002, the parties, including the Town of Milton and the DPS, entered into a Conceptual Agreement that outlined a negotiated settlement on relicensing, including the removal of Peterson Dam.

In January 2003, the Company, the Vermont Agency of Natural Resources ("Agency"), VNRC and other parties reached an agreement to allow us to relicense the four dams we own and operate on the Lamoille River. According to the agreement, we will receive a water quality certificate from the State, which is needed for FERC to relicense the facilities for 30 years. The agreement also stipulates that subject to various conditions, we must begin decommissioning Peterson Dam in about 20 years. The agreement requires PSB approval of full rate recovery related to decommissioning the Peterson Dam including full rate recovery of replacement power costs when the dam is out of service. On July 31, 2003, the Agency published its draft water quality certificate and on October 29, 2003, pursuant to the schedule set forth in the agreement, we filed a petition with the PSB for approval of the rate recovery mechanisms. We anticipate the PSB will establish a schedule for additional testimony, discovery and an order in 2004. We cannot predict the outcome of this matter.

Nuclear Generating Companies We are one of several sponsor companies with ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. We are responsible for paying our ownership percentage of decommissioning costs and all other costs for each plant. These companies have permanently shut down generating activities and are conducting decommissioning activities. We also have a 1.7303 percent joint-ownership interest in Millstone Unit #3. Our obligations related to the eventual decommissioning of the Vermont Yankee plant ceased when the plant was sold to Entergy on July 31, 2002.

Millstone Unit #3 We have an external trust dedicated to funding our joint ownership share of future decommissioning for Millstone Unit # 3. As a joint owner, we are responsible for our share of nuclear decommissioning costs. Contributions to the Millstone Unit #3 Trust Fund have been suspended based on the lead owner's representation to various regulatory bodies that the Trust Fund, for its share of the plant, exceeded the Nuclear Regulatory Commission's minimum calculation required. We could choose to renew funding at our own discretion as long as the minimum requirement is met or exceeded.

Maine Yankee, Connecticut Yankee and Yankee Atomic Our share of estimated future payments related to the decommissioning of Maine Yankee, Connecticut Yankee and Yankee Atomic, based on current forecasts for each plant, are as follows (dollars in millions):

	Date of Study	Total Obligation (a)	Remaining Obligation (b)	Revenue Requirements (c)	Company Share (d)
Maine Yankee	2003	$695.0	$220.7	$364.4	$7.4
Connecticut Yankee	2003	$1,004.7	$543.9	$666.4	$13.3
Yankee Atomic	2003	$667.3	$237.4	$181.3	$7.5

(a) Estimated total decommissioning cost for each plant in 2003 dollars.
(b) Estimated remaining decommissioning costs in 2003 dollars for the period 2004 through 2023 for Maine Yankee and Connecticut Yankee, and through 2022 for Yankee Atomic.
(c) Estimated future payments required by the Sponsor companies to recover estimated decommissioning and all other costs for 2004 and forward, in nominal dollars. For Maine Yankee and Connecticut Yankee includes collections for required contributions to spent fuel funds as described below. Yankee Atomic has already collected and paid these required contributions.
(d) Represents our share of revenue requirements based on our ownership percentages. For Yankee Atomic, this includes $1.1 million related to 2003. See discussion below for more detail.

Maine Yankee, Connecticut Yankee and Yankee Atomic are seeking recovery of fuel storage related costs stemming from the default of the United States Department of Energy ("DOE") under the 1983 fuel disposal contracts that were mandated by the United States Congress under the High Level Waste Act. These damage claims are now pending in the Federal Court of Claims. The trial is expected to begin in July 2004. The fuel storage related costs associated with the damage claims are included in each company's estimated total obligation, shown in the table above. None of the plants have included any allowance for potential recovery of these claims in their estimates.

Our share of each plant's estimated revenue requirements is reflected on the Consolidated Balance Sheets as either regulatory assets or other deferred charges, and nuclear decommissioning liabilities (current and non-current). At December 31, 2003, we had regulatory assets of about $7.4 million related to Maine Yankee and $3.0 million related to Connecticut Yankee. These estimated costs are being collected from our customers through existing retail and wholesale rate tariffs. At December 31, 2003, we also had other deferred charges of about $10.3 million related to incremental dismantling costs for Connecticut Yankee and $7.5 million for Yankee Atomic. These amounts are not currently being collected from customers through existing rates. On October 29, 2003, the PSB approved an Accounting Order for treatment of these incremental costs as other deferred charges, to be addressed in its next rate proceeding. We will adjust the associated regulatory assets, other deferred charges and nuclear decommissioning liabilities when revised estimates are provided.

Maine Yankee: We have a 2 percent ownership interest in Maine Yankee. Costs billed by Maine Yankee are expected to change in response to their October 21, 2003 filing at FERC. Maine Yankee's current billings to sponsor companies are based on their rate case settlement approved by FERC on June 1, 1999 under which costs were to be recovered through October 2008. In that settlement, Maine Yankee also agreed to file a FERC rate proceeding with an effective date for new rates no later than January 1, 2004. In the current filing the cost recovery period is proposed to extend to 2010.

Connecticut Yankee: We have a 2 percent ownership interest in Connecticut Yankee. Costs currently billed by Connecticut Yankee are based on its most recent FERC-approved rates, which became effective September 1, 2000, for collection through 2007. These amounts are being collected from our customers through existing rates.

Connecticut Yankee is involved in a contract dispute with Bechtel Power Corporation ("Bechtel"), which resulted in termination of the decommissioning services contract between Connecticut Yankee and Bechtel. This is a commercial contract dispute regarding Bechtel's performance; it is not related to safety, security or workmanship issues. As a result of contract termination, on July 14, 2003, Connecticut Yankee became the general contractor for the decommissioning.

On June 23, 2003, Bechtel responded to the notice of termination by filing a complaint for breach of contract, misrepresentation, and bad faith, in Connecticut Superior Court. After the contract termination, Bechtel amended its complaint to allege additional contract breaches (including wrongful termination) by Connecticut Yankee.

On August 22, 2003, Connecticut Yankee formally denied the allegations of Bechtel's amended complaint and filed a counterclaim. It alleges various material breaches of contract that justified Bechtel's termination, along with misrepresentation and bad faith. It also requests that Bechtel be found responsible for project costs in excess of Bechtel's unpaid contract balance, and for other damages. The lawsuit has been assigned to the Complex Litigation Docket and has been set for a jury trial beginning May 4, 2006. Connecticut Yankee also notified Bechtel's surety of its intention to file a claim under the performance bond.

At Connecticut Yankees' December 2003 Board of Directors meeting, the Board endorsed an updated estimate of the costs for the plant's decommissioning project. This updated cost estimate referred to as the "2003 Estimate" of approximately $823 million, covers the time period 2000 through 2023 and represents an aggregate increase of approximately $413 million in nominal dollars over the cost estimate in its 2000 FERC rate case settlement, which covered the same time period. It also includes increased costs from a November 2002 updated estimate which were related to projected costs of spent fuel storage, security, and liability and property insurance. The 2003 Estimate represents an increase of about $389 million in 2003 dollars. Prior to the approval of the cost estimate in the 2000 FERC settlement, Connecticut Yankee had also incurred about $184 million for decommissioning costs in the 1997 - 1999 timeframe.

The 2003 Estimate is still undergoing review; it reflects the fact that Connecticut Yankee is now directly managing the work (self performing) to complete decommissioning of the plant following the default termination of Bechtel as described above. Connecticut Yankee intends to update the estimate based on additional information when available including the results of competitive bidding of project work such as demolition. The 2003 Estimate does not include any allowance for relief of the Bechtel contract dispute or the DOE damage claim described above.

Connecticut Yankee is also beginning the preparation of a rate case application that is required to be filed with FERC by July 1, 2004 under the terms of its 2000 FERC rate case settlement. While Connecticut Yankee has not determined the relief it will seek in the forthcoming application, it anticipates that annual decommissioning collections would have to be increased significantly, beginning January 2005, to support anticipated project cash flow over the next several years and to fund long-term fuel storage through 2023.

Our estimated aggregate obligation related to Connecticut Yankee is about $13.3 million. The timing, amount and outcome of these filings cannot be predicted at this time. We believe our share of Connecticut Yankee's decommissioning costs are probable of recovery in future rate proceedings.

Yankee Atomic: We have a 3.5 percent ownership interest in Yankee Atomic. Billings from Yankee Atomic ended in July 2000 based on their determination that they had collected sufficient funds to complete the decommissioning effort. We are not currently collecting Yankee Atomic costs in retail rates.

In late 2002, Yankee Atomic revised its cost estimate for decommissioning the plant, reflecting an increase of about $190 million over prior estimates utilized by FERC. The increase was attributable to increases in projected costs of spent fuel storage, security, and liability and property insurance. In April 2003, Yankee Atomic filed with FERC for new rates to collect these costs from sponsor companies. FERC approved the resumption of billings starting June 2003 for a recovery period through 2010, subject to refund. The Company expects its share of these costs will be recoverable in future rates. In 2003, our share of Yankee Atomic's billings amounted to about $1.1 million. Based on a PSB-approved accounting order, we are deferring these costs.

DIVERSIFICATION

Catamount Resources Corporation was formed to hold our subsidiaries that invest in unregulated businesses including Catamount and Eversant.

Catamount As of December 31, 2003, Catamount has interests in nine operating independent power projects located in Rumford, Maine; East Ryegate, Vermont; Hopewell, Virginia; Rupert and Glenns Ferry, Idaho; Nolan County, Texas; Thetford, England; Thuringen, Germany and Mecklenburg-Vorpommern, Germany.

Catamount is primarily focused on developing, owning and operating wind energy projects and is currently pursuing the sale of certain of its interests in non-wind electric generating assets. Depending on prices, capital and other requirements, Catamount will also entertain offers for the purchase of any of its remaining non-wind electric generating assets. Proceeds from the sales will be reinvested in the development of new wind projects and the acquisition of existing wind projects. Additionally, Catamount is seeking investors and partners to co-invest with

Catamount in the development, ownership and acquisition of projects, which will be financed by equity and non-recourse debt. Management cannot predict the timing or outcome of potential future asset sales or whether this strategy will be successful.

Catamount has projects under development in the United States and United Kingdom. In February 2002, Catamount entered into a joint development agreement with force9energy Ltd. of England to develop wind projects in England, Scotland and Wales. In September 2002, Catamount established Catamount Energy Ltd., an English corporation, to hold Catamount's interests in England, Scotland and Wales "greenfield" development projects or projects that would be purchased by Catamount in early to mid-stage development. In July 2003, Catamount established Catamount Cymru Cyf., an English and Wales private limited company to develop a project located in Wales.

In January 2004, Catamount Energy Limited and Catamount Cymru Cyf. issued stock to a third party Norwegian investor thereby diluting Catamount's interest to 50 percent.

In June 2001, Catamount established Catamount Development GmbH, a German corporate entity, 100 percent owned by Catamount Heartlands Corp., a wholly owned subsidiary of Catamount. The company was formed to hold Catamount's interests in German "greenfield" development projects or projects that would be purchased by Catamount in early to mid-stage development. In 2003, Catamount ceased "greenfield" development in Germany to focus development efforts in the United States and United Kingdom.

Catamount Results

In the third quarter of 2003, the consolidated federal income tax provision reflected a benefit of approximately $2.3 million. Capital gain treatment on the proposed sale of Connecticut Valley (which closed January 1, 2004) allowed for a reduction of certain income tax valuation allowances at Catamount (Fibrothetford Limited $1.7 million, Glenns Ferry and Rupert $0.6 million), reflecting Management's best estimate that deferred income taxes for certain previously recorded equity losses will be realized.

Excluding these income tax benefits, Catamount recorded losses of about $1.6 million in 2003, primarily due to lower equity earnings and lower project development revenue, offset by lower interest expense due to lower debt. This compares to earnings of $1.5 million in 2002 and losses of $8.7 million in 2001. Its 2002 earnings compared to 2001 reflect higher equity in earnings from several of its investments and realized development revenue upon the sale of one of its investments in the fourth quarter of 2002, offset by after-tax asset impairment charges of $2.1 million taken for its investments that were sold in the fourth quarter of 2002. Also in 2001, Catamount had after-tax asset impairment charges of about $9.8 million related to several of its investments. Information regarding certain of Catamount's investments follows.

Glenns Ferry and Rupert Catamount is negotiating with a third party for the sale of its investment interests in Rupert and Glenns Ferry. Catamount cannot predict whether a sale will ultimately be consummated. Previously, in the fourth quarter 2001, Catamount recorded after-tax impairment charges of $3 million for all of its interests in the Rupert and Glenns Ferry projects due to the deteriorating financial condition of the projects' steam hosts essential to the projects' Qualifying Facility status and long-term viability.

In May 2002, Rupert and Glenns Ferry were issued an Events of Default notice by their lender. Steam host restructurings in 2002 cured most of the events of default. Rupert cured its remaining events of default in March 2003 and management anticipates that Glenns Ferry will cure its remaining events of default by the end of 2004. Management does not believe this will have a material impact on Catamount.

Sweetwater 1 On June 30, 2003, Catamount entered into an equity commitment for up to a $10.1 million equity investment in the 37.5-MW wind farm in Nolan County, Texas known as Sweetwater 1. The project's financial advisor located an additional equity investor for the project, reducing Catamount's equity commitment. In December 2003, Catamount acquired its equity interest in Sweetwater 1 for $6.2 million.

Fibrothetford Limited Catamount had a Sale and Purchase Agreement with a third party for the sale of its Fibrothetford investment interests. In July 2003, the buyer suspended the sale and in December 2003, Catamount terminated the Sale and Purchase Agreement. The buyer is still interested in acquiring Catamount's investment interests, but Catamount cannot predict whether a sale will ultimately be consummated.

To the extent required, continuing equity losses are applied as a reduction to Catamount's note receivable balance from Fibrothetford. In 2003, Catamount reserved approximately $2 million against interest income on the note receivable. Previously, in the fourth quarter of 2001, Catamount recorded an after-tax impairment charge of $3.2 million and a valuation allowance for the $2.2 million deferred tax asset. The impairment charge was based on the expected market value of Catamount's interest given the project's financial condition at the time.

Heartlands Power Limited and Gauley River In the fourth quarter of 2002 Catamount sold its interest in Heartlands Power Limited and Gauley River. The proceeds from the sales approximated the net book value of its investments in both projects. Also, in the third quarter of 2002, Catamount recorded after-tax impairment charges of $1.3 million related to Heartlands and $0.8 million related to Gauley River. At the time, the 2002 impairment charges were related to the pending sale of Heartlands, and funding requirements as a condition of the Gauley River Purchase and Sale Agreement. In 2001, Catamount recorded an after-tax impairment charge of $1.4 million related to Gauley River based on bids received from third parties, less estimated costs to sell.

Eversant As of December 31, 2003, Eversant had a $1.4 million equity investment, representing a 12 percent ownership interest in HSS, which has established a network of affiliate contractors who perform home maintenance repair and improvements for HSS members. Eversant accounts for this investment on a cost basis. In the third quarter of 2001, Eversant recorded a $1.2 million after-tax write-down of its investment in HSS to fair value based on an updated valuation at the time.

During 2001, AgEnergy (formerly SmartEnergy Control Systems), a wholly owned subsidiary of Eversant, filed a claim in arbitration against Westfalia-Surge, the exclusive distributor that marketed and sold its SmartDrive Control product. The arbitration concerned AgEnergy's claim that Westfalia-Surge had not conducted itself in accordance with the exclusive distributorship agreement between the parties. On January 28, 2002, AgEnergy received an adverse decision related to the arbitration. On November 6, 2002, Westfalia filed a Petition to Confirm the Arbitrator's Award, which effectively sought to expand the Arbitrator's Award. AgEnergy sought dismissal of the Petition to the extent it sought costs in excess of those established by the Arbitrator. The Petition was dismissed for lack of jurisdiction.

Eversant's wholly owned subsidiary, SmartEnergy Water Heating Services, Inc. ("SEWHS"), engages in the sale or rental of electric water heaters in Vermont and New Hampshire. SEWHS had earnings of $0.5 million in 2003, $0.3 million in 2002 and $0.4 million in 2001.

Overall, Eversant's 2003 earnings were $0.5 million, versus net losses of $0.5 million in 2002 and $2.1 million in 2001. In early 2002, we discontinued Eversant's efforts to pursue unregulated business opportunities except for SEWHS.

INCOME TAX ISSUES

We account for income taxes in accordance with SFAS No. 109 which requires recognition of deferred tax assets and liabilities for the future tax effects of temporary differences between carrying amounts and the tax basis of assets and liabilities. Under this method, deferred income taxes result from applying the statutory rates to the differences between the book and tax basis of asset and liabilities.

Valuation Allowances 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. From January 1, 2003 to December 31, 2003, the valuation allowance decreased by about $3.4 million. All other deferred income taxes are expected to be realized. The $3.4 million decrease is related to the following:

- In the third quarter of 2003, Management determined that the Connecticut Valley sale agreement was more likely than not to occur, which afforded the Company the opportunity to realize capital gains on the sale. The capital gains treatment allowed for a $2.3 million reduction of certain tax valuation allowances at Catamount. These tax valuation allowances were primarily related to previously recorded equity losses resulting from fourth quarter 2001 asset impairments charges taken at Catamount for certain of its investments. At that time, the Company had determined that it was more likely than not that current or future income tax benefits would not be realized for these asset impairment charges, and it was Management's best estimate that it would not realize enough capital gains to offset the potential capital losses resulting from the asset impairment charges.

- In the third quarter of 2003, the Company reduced the valuation allowance and corresponding deferred tax asset by about $1.9 million due to the reclassification of an equity method of accounting adjustment related to the financial statements from one of Catamounts foreign projects. This reclassification did not impact 2003 earnings.
- During 2003 additional valuation allowances of about $0.8 million were established for certain foreign losses related to Catamount's foreign investments. Management determined that it is more likely than not that a current or future income tax benefit would not be realized.

RECENT ACCOUNTING PRONOUNCEMENTS

See Note 1 to the accompanying Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Regulatory Risk Electric utility rates in Vermont are based on a utility's costs of service. As such, we are subject to Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71") which allows 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. If we determine the Company no longer meets the criteria under SFAS No. 71, the accounting impact would be an extraordinary charge to operations of about $41.8 million pre-tax basis as of December 31, 2003, assuming no stranded cost recovery would be allowed through a rate mechanism.

If retail competition is implemented in our Vermont service territory, we are unable to predict the impact on our revenues, our ability to retain existing customers and attract new customers or the margins that will be realized on retail sales of electricity, if any such sales are sought.

Interest Rate Risk As of December 31, 2003, we have $16.3 million of Industrial Development/Pollution Control bonds outstanding ($10.8 million with an interest rate that floats monthly based on short-term credit markets and $5.5 million that floats every five years based on comparable credit markets. All other utility debt has a fixed rate. There are no interest lock or swap agreements in place. Consolidated temporary cash investments amounted to $55.2 million at December 31, 2003, including $12.4 million related to the non-utility business. Interest rate changes could also affect estimates of pension and other benefit liabilities and expenses that could potentially require contributions to the pension trusts.

Equity Market Risk As of December 31, 2003, the pension trust and Millstone Unit #3 decommissioning trust held marketable equity securities of $42.5 million and $3.2 million, respectively. We also maintain a variety of insurance policies in a Rabbi Trust with a current value of $5.2 million. The current values of certain policies are affected by changes in the equity market.

Credit Risk We have $16.9 million of letters of credit expiring on November 30, 2004, secured by a first mortgage lien on the same collateral supporting our First Mortgage Bonds. At December 31, 2003, the utility long-term debt maturities and sinking fund requirements is $75 million related to our Second Mortgage Bonds that mature on August 1, 2004. We are considering alternative refinancing arrangements and currently, we intend to and have the ability to refinance the $75 million at maturity. No payments are due on long-term debt for 2005 through 2007.

The Second Mortgage Bonds covenants contain limiting restrictions if those bonds receive a debt rating below BBB- from rating agencies. The current ratings of the bonds are BBB- (stable) from Standard & Poor's and BBB (stable) from Fitch. The limiting characteristics include, but are not limited to, certain restrictions on investments in unregulated subsidiaries, the incurrence of indebtedness and the payment of dividends. These restrictions are dependent on meeting both a Fixed Charge Coverage and a Cumulative Cash Flow test. We are currently in compliance with both calculations.

Unregulated Business - Catamount

Credit Risk In December 2002, Catamount extended its corporate credit facility to November 2004. In February 2004, Catamount notified the lender of its intent to terminate the credit facility (the termination is effective 90 days after such notification.) Catamount is currently soliciting proposals from selected financial institutions for corporate and/or development credit facilities to meet its business needs. Catamount cannot predict whether it will be able to ultimately solicit and enter into an appropriately priced corporate and/or development credit facility.

Also see Item 7, Risk Factors for a more detailed discussion of business risks.

Item 8. Financial Statements and Supplementary Data.

Index to Financial Statements and Supplementary Data

Independent Auditors' Report
To the Board of Directors 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, 2003 and 2002, 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, 2003. 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 auditing standards generally accepted in the United States of America. 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, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Central Vermont Public Service Corporation and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 4 to the consolidated financial statements, Connecticut Valley Electric Company, a wholly owned subsidiary of the Company, completed the sale of substantially all of its plant assets and its franchise to Public Service Company of New Hampshire on January 1, 2004.

Deloitte & Touche, LLP

Boston, Massachusetts
February 20, 2004

CONSOLIDATED STATEMENTS OF INCOME

(in thousands, except per share amounts)	Year Ended December 31 2003	2002	2001
Operating Revenues	**$306,014**	$294,390	$292,900
Operating Expenses			
Operation			
Purchased power	**152,994**	142,430	143,395
Production and transmission	**26,031**	25,490	24,485
Other operation	**46,732**	43,454	42,790
Maintenance	**16,816**	17,477	18,061
Depreciation	**15,930**	16,467	16,560
Other taxes, principally property taxes	**13,367**	12,860	12,248
Taxes on income	**10,125**	11,009	10,182
Total operating expenses	**281,995**	269,187	267,721
Operating Income	**24,019**	25,203	25,179
Other Income and Deductions			
Equity in earnings of affiliates	**1,801**	3,909	2,668
Allowance for equity funds during construction	**87**	71	60
Other income, net	**2,718**	1,582	(16,309)
(Provision) benefit for income taxes	**1,470**	(82)	2,966
Total other income and deductions, net	**6,076**	5,480	(10,615)
Total Operating and Other Income	**30,095**	30,683	14,564
Interest Expense			
Interest on long-term debt	**11,231**	12,526	12,843
Other interest	**547**	(32)	997
Allowance for borrowed funds during construction	**(38)**	(35)	(30)
Total interest expense, net	**11,740**	12,459	13,810
Income from continuing operations	**18,355**	18,224	754
Income from discontinued operations, net of tax	**1,446**	1,543	1,653
Net income	**19,801**	19,767	2,407
Dividends on preferred stock	**1,198**	1,528	1,696
Earnings Available For Common Stock	**18,603**	18,239	711
Per Common Share Data:			
Basic			
Earnings (loss) from continuing operations	**$1.45**	$1.43	$(.08)
Earnings from discontinued operations	**.12**	.13	.14
Earnings per share	**$1.57**	$1.56	$.06
Average shares of common stock outstanding	**11,884,147**	11,678,239	11,551,042
Diluted			
Earnings (loss) from continuing operations	**$1.41**	$1.40	$(.08)
Earnings from discontinued operations	**.12**	.13	.14
Earnings per share	**$1.53**	$1.53	$.06
Average shares of common stock outstanding	**12,119,553**	11,942,822	11,780,235
Dividends Paid per Share of Common Stock	**$.88**	$.88	$.88

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)	Years Ended December 31		
	2003	2002	2001
Net Income	**$19,801**	$19,767	$2,407
Other comprehensive income (loss), net of tax:			
Foreign currency translation adjustments	**456**	800	(349)
Unrealized loss on investment	**(44)**	-	-
Non-qualified benefit obligation	**(77)**	(27)	(5)
	335	773	(354)
Comprehensive income	**$20,136**	$20,540	$2,053

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31		
	2003	2002	2001
Cash Flows Provided (Used) By:			
Operating Activities			
Income from continuing operations	**$18,355**	$18,224	$754
Adjustments to reconcile net income to net cash provided by operating activities			
Equity in earnings of affiliates	**(1,801)**	(3,909)	(2,668)
Dividends received from affiliates	**2,441**	4,040	2,773
Equity in earnings from non-utility investments	**(6,362)**	(11,603)	(6,079)
Distribution of earnings from non-utility investments	**12,915**	10,639	4,636
Depreciation	**15,930**	16,467	16,560
Vermont Utility mandated earnings cap	**2,475**	681	-
Regulatory Asset write-off	**-**	-	9,000
Asset impairment charges, including tax valuation allowance	**142**	2,774	8,905
Investment write-down	**-**	-	1,963
Amortization of capital leases	**1,097**	1,143	1,089
Deferred income taxes and investment tax credits	**(2,657)**	3,058	(4,937)
Reversal of deferred income tax valuation allowance	**(2,293)**	-	-
Net (deferral) amortization of nuclear replacement energy and maintenance costs	**653**	3,683	(2,517)
Amortization of conservation and load management costs	**1,461**	2,217	3,144
Net deferral of restructuring costs	**-**	-	(1,389)
Decrease in accounts receivable and unbilled revenues	**874**	561	5,333
(Decrease) increase in accounts payable	**(440)**	61	(3,763)
(Decrease) increase in accrued income taxes	**(755)**	877	(1,614)
Change in other working capital items	**(3,200)**	4,864	(6,634)
Increase in pension liability	**2,520**	754	1,185
Change in environmental reserve	**(1,088)**	(1,844)	(285)
Deferred Vermont Yankee fuel rod costs	**982**	(3,854)	-
Deferred Vermont Yankee sale costs	**-**	(8,197)	-
Other, net	**5,405**	1,934	4,760
Net cash provided by operating activities of continuing operations	**46,654**	42,570	30,216
Investing Activities			
Construction and plant expenditures	**(14,959)**	(13,885)	(16,148)
Conservation and load management expenditures	**(104)**	(236)	(504)
Return of capital	**14,040**	336	641
Proceeds from sale of non-utility assets	**-**	13,335	-
Non-utility investments	**(6,377)**	(253)	(13,671)
Utility investments	**(177)**	(449)	-
Other investments, net	**(290)**	(258)	(474)
Net cash used for investing activities of continuing operations	**(7,867)**	(1,410)	(30,156)
Financing Activities			
Sale of treasury stock	**2,348**	416	556
Proceeds from dividend reinvestment program	**1,794**	1,309	-
Retirement of preferred stock	**-**	(6,000)	-
Retirement of long-term debt	**(29,381)**	(8,208)	(4,201)
Restricted cash	**10,560**	(12,560)	-
Issuance of long-term debt	**-**	-	14,017
Common and preferred dividends paid	**(11,640)**	(12,222)	(11,433)
Reduction in capital lease obligations	**(1,097)**	(1,143)	(1,089)
Net cash used for financing activities of continued operations	**(27,416)**	(38,408)	(2,150)
Effect of exchange rate changes on cash	**(497)**	118	-
Cash flows used by discontinued operations	**(531)**	(557)	(405)
Net Increase (Decrease) In Cash and Cash Equivalents	**10,343**	2,313	(2,495)
Cash and Cash Equivalents at Beginning of Year	**47,804**	45,491	47,986
Cash and Cash Equivalents at End of Year	**$58,147**	$47,804	45,491
Supplemental Cash Flow Information			
Cash paid during the year for:			
Interest (net of amounts capitalized)	**$11,086**	$12,657	$13,871
Income taxes (net of refunds)	**$14,978**	$10,773	$16,892
Non-cash Operating, Investing and Financing Activities			
Stock award plans (Note 9), Regulatory assets (Notes 1 and 12), and Long-term lease arrangements (Note 13)			

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

CONSOLIDATED BALANCE SHEETS

(in thousands)	December 31 **2003**	2002
Assets		
Utility Plant, at original cost	**$495,162**	$487,184
Less accumulated depreciation	**207,474**	197,648
Net utility plant	**287,688**	289,536
Construction work-in-progress	**9,988**	9,049
Nuclear fuel, net	**1,016**	1,130
Total utility plant	**298,692**	299,715
Investments and Other Assets		
Investments in affiliates	**9,303**	23,716
Non-utility investments	**34,765**	35,087
Non-utility property, less accumulated depreciation	**2,236**	2,224
Millstone decommissioning trust fund	**4,340**	3,659
Other	**5,249**	4,237
Total investments and other assets	**55,893**	68,923
Current Assets		
Cash and cash equivalents	**58,147**	47,804
Restricted cash	**2,000**	12,560
Notes receivable	**3,750**	3,750
Accounts receivable, less allowance for uncollectible accounts ($1,578 in 2003 and $1,248 in 2002)	**21,900**	23,945
Unbilled revenues	**17,505**	15,985
Materials and supplies, at average cost	**3,699**	3,341
Prepayments	**3,226**	2,375
Other current assets	**2,522**	736
Assets held for sale	**9,292**	9,242
Total current assets	**122,041**	119,738
Deferred Charges and Other Assets		
Regulatory Assets	**17,555**	22,430
Other deferred charges - regulatory	**30,929**	24,147
Other	**6,209**	5,896
Total deferred charges and other assets	**54,693**	52,473
Total Assets	**$531,319**	$540,849

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

CONSOLIDATED BALANCE SHEETS

	December 31 2003	2002
Capitalization and Liabilities		
Capitalization		
Common stock, $6 par value, authorized 19,000,000 shares (issued 11,807,495 and 11,807,495)	**$72,119**	$70,845
Other paid-in capital	**51,334**	48,434
Accumulated other comprehensive income	**485**	150
Deferred compensation plans-employee stock ownership plans	**(969)**	(1,041)
Treasury stock, at cost (0 and 64,854 shares)	**-**	(857)
Retained earnings	**88,282**	80,077
Total common stock equity	**211,251**	197,608
Preferred and preference stock	**8,054**	8,054
Preferred stock with sinking fund requirements	**9,000**	10,000
Long-term debt	**126,750**	137,908
Capital lease obligations	**10,693**	11,762
Total capitalization	**365,748**	365,332
Current Liabilities		
Current portion of preferred stock	**1,000**	-
Current portion of long-term debt	**2,657**	20,879
Accounts payable	**6,650**	5,572
Accounts payable - affiliates	**10,985**	11,665
Accrued interest	**2,801**	2,984
Nuclear decommissioning costs	**4,026**	3,263
Other current liabilities	**18,893**	18,286
Liabilities of assets held for sale	**5,499**	5,987
Total current liabilities	**52,511**	68,636
Deferred Credits and Other Liabilities		
Deferred income taxes	**36,713**	41,766
Deferred investment tax credits	**4,880**	5,267
Nuclear decommissioning costs	**22,934**	20,899
Asset retirement obligations	**3,449**	-
Other	**45,084**	38,949
Total deferred credits and other liabilities	**113,060**	106,881
Commitments and Contingencies		
Total Capitalization and Liabilities	**$531,319**	$540,849

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

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY
(dollars in thousands)

	Common Stock Shares	Common Stock Amount	Other Paid-in Capital	Deferred Compensation Plan - Employee Stock	Accumulated Other Comprehensive Income	Treasury Stock	Retained Earnings	Total
Balance, December 31, 2000	11,507,980	$70,715	$45,810	$(358)	$(269)	$(3,624)	$78,423	$190,697
Treasury stock (at cost) for stock compensation plans	102,703					1,339	(41)	1,298
Net income							2,407	2,407
Other comprehensive income net of taxes					(354)			(354)
Allocation of benefits - employee stock				1,074				1,074
Unearned stock compensation			1,802	(1,813)				(11)
Cash dividends on capital stock:								
Common - $.88 per share							(10,183)	(10,183)
Cumulative preferred (non-redeemable)							(368)	(368)
Cumulative preferred (redeemable)							(1,328)	(1,328)
Amortization of preferred stock issuance expenses			22					22
Other adjustments							260	260
Balance, December 31, 2001	11,610,683	$70,715	$47,634	$(1,097)	$(623)	$(2,285)	$69,170	$183,514
Treasury stock (at cost) for stock compensation plans	131,958					1,428	384	1,812
Net income							19,767	19,767
Other comprehensive income net of taxes					773			773
Allocation of benefits - employee stock				1,065				1,065
Unearned stock compensation			480	(1,009)				(529)
Cash dividends on capital stock:								
Common - $.88 per share							(7,716)	(7,716)
Cumulative preferred (non-redeemable)							(594)	(594)
Cumulative preferred (redeemable)							(934)	(934)
Amortization of preferred stock issuance expenses			39					39
Premium on capital stock			257					257
Dividend reinvestment plan		130						130
Other adjustments			24					24
Balance, December 31, 2002	11,742,641	$70,845	$48,434	$(1,041)	$150	$(857)	$80,077	$197,608
Common stock issuance:								
Treasury stock (at cost) for stock compensation plans	64,854					857		857
Stock compensation plans	213,243	692	2,778				44	3,514
Net income							19,801	19,801
Other comprehensive income net of taxes					335			335
Allocation of benefits - employee stock				932				932
Unearned stock compensation		22	95	(860)				(743)
Cash dividends on capital stock:								
Common - $.88 per share							(10,442)	(10,442)
Cumulative preferred (non-redeemable)							(368)	(368)
Cumulative preferred (redeemable)							(830)	(830)
Amortization of preferred stock issuance expenses			27					27
Dividend reinvestment plan		560						560
Balance, December 31, 2003	**12,020,738**	**$72,119**	**$51,334**	**$(969)**	**$485**	**$ -**	**$88,282**	**$211,251**

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

About Central Vermont Public Service Corporation Central Vermont Public Service Corporation ("the Company") is a Vermont-based electric utility that transmits, distributes and sells electricity, and invests in renewable and independent power projects. Wholly owned subsidiaries include: Connecticut Valley Electric Company, Inc. ("Connecticut Valley"), which distributes and sells electricity in New Hampshire; Catamount Energy Corporation ("Catamount"), which invests primarily in wind energy projects in the United States and the United Kingdom; and Eversant Corporation ("Eversant"), which operates a rental water heater business through its subsidiary, SmartEnergy Water Heating Services, Inc. See Note 4 - Discontinued Operations - Connecticut Valley Sale.

Consolidation Policy and Use of Estimates The consolidated financial statements include the accounts of the Company and its subsidiaries in which it has a controlling interest. Intercompany transactions have been eliminated in consolidation.

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 its operation. Under this method, the Company records its ownership share of the net income or loss of each investment in the accompanying consolidated financial statements.

The Company's interests in jointly owned generating and transmission facilities are accounted for on a pro-rata basis using the Company's ownership percentages and are recorded in the Company's Consolidated Balance Sheets. The Company's share of operating expenses for these facilities is included in the corresponding operating accounts on the Consolidated Statements of Income.

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America 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.

Utility Regulation The Company is regulated by the Vermont Public Service Board ("PSB"), the New Hampshire Public Utilities Commission ("NHPUC"), 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 Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71"), for its regulated Vermont service territory, FERC-regulated wholesale business and Connecticut Valley's New Hampshire service territory. In order for a company to report under SFAS No. 71, the company's 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 the 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. Management periodically reviews these criteria to ensure the continuing application of SFAS No. 71 is appropriate. 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 and the State of New Hampshire for its retail and wholesale businesses is probable.

Discontinued Operations The assets and liabilities of Connecticut Valley are classified as held for sale in the Consolidated Balance Sheets in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, ("SFAS No. 144"). In addition, as required by SFAS No. 144, the results of operations related to Connecticut Valley are reported as discontinued operations, and prior periods have been restated to conform to this presentation. For presentation purposes, certain of the Company's common corporate costs, which were previously allocated to Connecticut Valley, have been reallocated back to continuing operations to reflect the impact of the sale on continuing operations. These common costs amounted to about $1.3 million in 2003, $1.4 million in 2002 and $1.1 million in 2001, on an after-tax basis. The Company began to present Connecticut Valley as discontinued operations in the second quarter of 2003 based on the NHPUC's approval of the sale of Connecticut Valley's plant assets and franchise to Public Service Company of New Hampshire ("PSNH"). Prior to the second quarter of 2003, Connecticut Valley was reported as a separate segment. The sale was completed on January 1, 2004. See Note 4 - Discontinued Operations - Connecticut Valley Sale.

Unregulated Business Results of operations of Catamount and Eversant are included in Other income, net in the Other Income and Deductions section of the Consolidated Statements of Income. Catamount's policy is to expense all screening, feasibility and development expenditures associated with investments in new projects. Catamount's project costs incurred subsequent to obtaining financial viability are recognized as assets subject to depreciation or amortization. Project viability is obtained when it becomes probable that costs incurred will generate future economic benefits sufficient to recover these costs. See Note 3 - Non-Utility Investments.

Revenues Revenues related to the sale of electricity are generally recorded when service is rendered or electricity is distributed to customers. Electricity sales to customers are based on monthly meter readings. Estimated unbilled revenues are recorded at the end of each monthly accounting period. In order to determine unbilled revenues, the Company makes various estimates including 1) energy generated, purchased and resold, 2) losses of energy over transmission and distribution lines, 3) kilowatt-hour usage by retail customer mix - residential, commercial and industrial, and 4) average retail customer pricing rates. Unbilled revenues at year end were $17.5 million in 2003, $16.0 million in 2002 and $16.4 million in 2001.

Purchased Power The Company records power purchased under long-term contracts as operating expenses. The contracts are considered executory in nature, since they do not convey to the Company the right to use the related property, plant or equipment. This accounting treatment is in contrast to the Company's commitment with respect to the Hydro-Quebec Phase I and II transmission facilities, which are considered capital leases. See Note 13 - Commitments and Contingencies.

Income Taxes In accordance with SFAS No. 109, *Accounting for Income Taxes* ("SFAS No. 109"), the Company recognizes 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 unless it is more likely than not such tax assets will be unrealized. See Note 11 - Income Taxes.

Net 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 original cost of units retired, net of salvage value, are charged to accumulated provision for depreciation. The primary components of utility plant include (in thousands):

	December 31	
	2003	2002
Electric - transmission and distribution	**$372,090**	$363,571
Jointly owned generation and transmission units	**109,321**	109,110
Property under capital leases	**11,790**	12,887
Completed construction	**1,918**	1,573
Held for future use	**43**	43
Utility plant, at original cost	**495,162**	487,184
Less accumulated depreciation	**207,474**	201,908
Net Utility Plant	**$287,688**	285,276

Depreciation The Company uses the straight-line remaining life method of depreciation. Total depreciation expense was 3.28 percent of the cost of depreciable utility plant in 2003, 3.34 percent in 2002 and 3.53 percent in 2001.

Allowance for Funds Used During Construction Allowance for funds used during construction ("AFUDC") is the cost of debt and equity financing during construction projects. The Company capitalizes AFUDC 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 ratemaking proceedings. AFUDC equity represents a current non-cash credit to earnings, recoverable over the life of the property. AFUDC rates used by the Company were 9.3 percent in 2003, 9.3 percent in 2002 and 9.4 percent in 2001.

Regulatory Assets, Deferred Charges and Regulatory Liabilities 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. 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 related regulatory assets, certain other deferred charges and regulatory liabilities which are summarized in the table that follows.

	(in thousands)	
Net Regulatory Assets, Deferred Charges and Regulatory Liabilities	**December 31 2003**	December 31 2002
Regulatory assets *		
Conservation and load management ("C&LM") (a)	**$517**	$1,853
Nuclear refueling outage costs - Millstone	**109**	762
Income taxes	**5,640**	5,849
Maine Yankee nuclear power plant dismantling costs (b)	**7,287**	8,959
Connecticut Yankee nuclear power plant dismantling costs (b)	**2,980**	3,774
Unrecovered plant and regulatory study costs	**874**	1,099
Other regulatory assets	**148**	134
Subtotal Regulatory assets	**17,555**	22,430
Other deferred charges - regulatory		
Vermont Yankee fuel rod maintenance deferral **	**3,101**	3,854
Vermont Yankee sale costs **	**8,704**	8,197
Yankee Atomic incremental dismantling costs (b)	**7,481**	7,872
Connecticut Yankee incremental dismantling costs (b)	**10,347**	3,558
Unrealized loss on power contract derivatives (c)	**1,296**	666
Subtotal Other deferred charges - regulatory	**30,929**	24,147
Other deferred credits ***		
Hydro-Quebec ice storm settlement	**-**	8
Millstone Decommissioning (d)	**304**	-
IPP Settlement Reimbursement and VEPPI cost mitigation (e)	**757**	99
Vermont utility mandated earnings cap (f)	**3,220**	681
Vermont Yankee NEIL Insurance refund (g)	**461**	-
Asset Retirement Obligation - Millstone Unit #3 (h)	**891**	-
Unrealized gain on power contract derivative (c)	**444**	-
Other regulatory liabilities	**602**	493
Subtotal Other deferred credits	**6,679**	1,281
Net Regulatory assets, deferred charges and other deferred credits	**$41,805**	$45,296

* Regulatory assets are currently being recovered in rates and, with the exception of C&LM and other regulatory assets, include an associated return.

** These items include a provision for carrying costs and will be addressed in the Company's next rate proceeding, per the approved PSB Accounting Orders that are associated with them.

*** Included in Other in Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

a) The Company completed amortizing certain C&LM costs in August 2003. The remaining balance is related to deferred costs associated with implementing programs promoting system-wide energy efficiencies and estimated lost revenues resulting from those programs.

b) Regulatory assets related to Connecticut Yankee and Maine Yankee represent estimated decommissioning costs that are being collected from the Company's customers through its existing retail rate tariffs. The estimated incremental dismantling costs for these facilities and for Yankee Atomic that are not included in retail rates are recorded as deferred charges. In October 2003, the PSB approved an Accounting Order for treatment of these incremental costs as deferred charges, to be addressed in the Company's next rate proceeding. Also see Note 13 - Commitments and Contingencies.

c) The Company records derivative contracts on the balance sheet at fair value. Based on a PSB approved Accounting Order, the changes in fair value of these derivatives are recorded as deferred charges or deferred credits on the balance sheet depending on whether the fair value is an unrealized loss or gain. See discussion of Derivative Financial Instruments below.

d) The Company is recovering Millstone Unit #3 decommissioning costs in rates, but its decommissioning payments have been suspended. Prior to January 1, 2003, these amounts were applied to reduce regulatory assets related to C&LM. Since January 1, 2003, funds collected for Millstone Unit #3 decommissioning are being recorded as a regulatory liability, which will continue to increase unless rates are adjusted to exclude such collections or the Company chooses or is required to renew funding in the future. This regulatory liability, including carrying costs, will be addressed in the Company's next rate proceeding.

e) As a result of the Independent Power Producers ("IPP") settlement, described in Note 13 - Commitments and Contingencies, in the first quarter of 2003, the Company received a reimbursement of approximately $0.3 million for legal costs from non-participating parties who derived benefits from the IPP negotiations. The PSB also approved the Company's request for treatment of savings credits resulting from the settlement as a regulatory liability, including carrying costs, to be addressed in its next rate proceeding. These savings, including carrying costs, and previous IPP savings, amounted to about $0.4 million in 2003 and $0.1 million in 2002.

f) The Vermont utility earned above its allowed rate of return on common equity of 11 percent in 2003 and in 2002. In order to stay within the mandated earnings cap, the Vermont utility's earnings were reduced by approximately $1.5 million in 2003 and $0.4 million in 2002. The Company deferred the related pre-tax amounts as regulatory liabilities, amounting to $2.5 million in 2003 and $0.7 million in 2002. In March 2003, the PSB approved treatment of the 2002 deferral as a regulatory liability, and the Company expects to seek PSB approval for similar treatment of the 2003 deferral. These regulatory liabilities, including carrying costs as applicable, are expected to be used to decrease Other deferred charges on the Consolidated Balance Sheet at December 31, 2003.

g) Pursuant to PSB approval of the Vermont Yankee sale, distributions from Nuclear Electric Insurance Limited ("NEIL") received by Vermont Yankee and passed to the sponsor companies must benefit ratepayers through programs to promote renewable resources. The $0.5 million represents the Company's share of Vermont Yankee's NEIL refund received in March 2003. The Company is developing a plan for use of these funds, which will require PSB approval.

h) See discussion of Asset Retirement Obligations below.

Other Deferred Credits The Company's other deferred credits and other liabilities at December 31, 2003 and 2002 include the following (in thousands):

	December 31	
	2003	2002
Accrued pension benefits	**$12,562**	$10,042
Accrued postretirement medical and other benefits	**7,877**	7,242
Environmental reserve (long-term portion)	**5,983**	7,072
Non-legal asset retirement obligation	**5,226**	4,260
Other deferred credits - regulatory	**6,679**	1,281
Deferred tax liabilities	**4,451**	4,385
Other	**2,306**	4,667
Total	**$45,084**	$38,949

Other Current Liabilities The Company's miscellaneous current liabilities at December 31, 2003 and 2002 include the following (in thousands):

	December 31	
	2003	2002
Accrued employee costs - payroll and medical	**$3,373**	$4,435
Other taxes and Energy Efficiency Utility	**3,254**	2,778
Deferred compensation plans	**2,749**	2,579
Customer deposits, prepayments and interest	**2,021**	1,293
Obligation under capital leases	**1,097**	1,094
Environmental and accident reserves	**1,755**	897
Accrued joint owned expenses	**302**	473
Accrued income taxes	**196**	951
Miscellaneous accruals	**4,146**	3,786
Total	**$18,893**	$18,286

Valuation of Long-Lived Assets The Company periodically evaluates the carrying value of long-lived assets and long-lived assets to be disposed of, 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. See Note 3 - Non-Utility Investments for discussion of impairment of non-utility investments.

Asset Retirement Obligations SFAS No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143") provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of long-lived assets. It also requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. The Company adopted SFAS No. 143 on January 1, 2003 as required and it did not have a cumulative effect on earnings upon adoption.

Legal Asset Retirement Obligations The Company has legal retirement obligations associated with decommissioning related to its investments in nuclear plants. The Company had about $3.4 million of asset retirement obligations recorded on the Consolidated Balance Sheet at December 31, 2003. The following table presents actual changes to asset retirement obligations during 2003 and the pro forma effects of the application of SFAS No. 143 as if the statement had been adopted on January 1, 2002, instead of January 1, 2003 (in millions):

	2003 (actual)	2002 (pro forma)
Asset retirement obligations at January 1	-	$3.1
Asset retirement obligations recognized in transition	**$3.3**	-
Accretion	**0.1**	0.2
Asset retirement obligation at December 31	**$3.4**	$3.3

The Company has an external trust dedicated to funding its joint ownership share of future decommissioning for Millstone Unit # 3. The year-end aggregate fair value of these trusts, consisting primarily of debt and equity securities, totaled $4.3 million in 2003 and $3.7 million in 2002, and is included in Investments and Other Assets on the Consolidated Balance Sheets. At December 31, 2003, the difference between the balance in the external trusts and the asset retirement obligation amounted to about $0.9 million and is recorded in Deferred credits and Other Liabilities on the Consolidated Balance Sheet.

Other Asset Retirement Obligations 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 $5.2 million in 2003 and $4.3 million in 2002 were previously recorded in Accumulated Depreciation. These regulatory liabilities have been reclassified to Deferred Credits and Other Liabilities on the Consolidated Balance Sheets.

Earnings Per Share Basic earnings per share ("EPS") is calculated by dividing net income, after deductions for preferred dividends, by the weighted-average common shares outstanding for the period. SFAS No. 128, *Earnings Per Share*, requires the disclosure of diluted EPS, which is similar to the calculation of basic EPS except that the weighted-average common shares is increased by the number of potential dilutive common shares. Diluted EPS reflects the impact of the issuance of common shares for all potential dilutive common shares outstanding during the period.

Stock-Based Compensation The Company applies Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* ("APB 25"), and related Interpretations in accounting for its stock option plans. In accordance with SFAS No. 148, *Accounting for Stock-Based Compensation - Transition and Disclosure - an amendment of SFAS No. 123*, the following table illustrates the effect on net income and earnings per share as if the fair value method had been applied to all outstanding and unvested awards in each period. The fair value of options at date of grant was estimated using the Black Scholes option-pricing model for 2003 and the binomial option-pricing model for 2002 and 2001.

	(in thousands, except per share amounts)		
		December 31	
	2003	2002	2001
Income available for common stock, as reported	**\$18,603**	\$18,239	\$711
Deduct: Total stock-based employee compensation expense *	**163**	147	118
Pro forma net income	**\$18,440**	\$18,092	\$593
Earnings per share:			
Basic - as reported	**\$1.57**	\$1.56	\$.06
Basic - pro forma	**\$1.55**	\$1.55	\$.05
Diluted - as reported	**\$1.53**	\$1.53	\$.06
Diluted - pro forma	**\$1.52**	\$1.51	\$.05

* Fair value-based method for all awards, net of related tax effects.

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 13 - Commitments and Contingencies.

Derivative Financial Instruments The Company accounts for various power contracts as derivatives under the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted (collectively "SFAS No. 133"). In April 2003, the Financial Accounting Standards Board ("FASB") issued SFAS No. 149, *Amendment of Statement 133 Derivative Instruments and Hedging Activities* ("SFAS No. 149"), which amends and clarifies accounting for derivative instruments under SFAS No. 133. This statement is effective for contracts entered into or modified after June 30, 2003. These statements require that derivatives be recorded on the Consolidated Balance Sheets at fair value. Adoption and application of these statements did not impact the Company's financial position or results of operation.

The Company has a long-term purchased power contract that allows the seller to purchase specified amounts of power with advance notice (Hydro-Quebec Sellback #3). This contract has been determined to be a derivative under SFAS No. 133. The derivative's year-end estimated fair value was an unrealized loss of \$1.2 million in 2003 and \$0.7 million in 2002. The estimated fair value of this derivative is based on quoted market information where available and appropriate modeling methodologies.

In December 2003, the Company entered into a forward sale contract for about 148,400 mWh for the period beginning January 1 and ending March 31, 2004, and a forward purchase contract for about 27,100 mWh for the month of April 2004. The contracts are intended to minimize the net costs and risks of serving customers, including replacement power related to Vermont Yankee's April 2004 scheduled refueling outage. Although these contracts are related to serving load requirements, they do not meet the normal purchase and sale exclusion under SFAS No. 149's amendments to SFAS No. 133. At December 31, 2003, the forward sale contract had an estimated fair value of a \$0.4 million unrealized gain, and the forward purchase contract had an estimated fair value of a \$0.1 million unrealized loss. The estimated fair value of these derivatives is based on quoted market information.

The Company records derivative contracts on the balance sheet at fair value. Based on a PSB approved Accounting Order, the Company records the change in fair value of these derivatives as deferred charges or deferred credits on the balance sheet, depending on whether the fair value is an unrealized loss or gain. See Net Regulatory Assets, Deferred Charges and Regulatory Liabilities table above for classification of these derivatives.

Foreign Currency Translation All foreign non-utility assets and liabilities are translated at the year-end currency exchange rate. Revenues and expenses are translated at average exchange rates in effect during the year. Realized gains or losses from foreign currency translations are included in earnings of the current period.

Cash, Cash Equivalents and Restricted Cash 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 of $2 million at December 31, 2003 is related to mandatory and optional sinking fund payments on the Company's preferred stock. Restricted cash of $12.6 million at December 31, 2002 was related to cash proceeds from Catamount's investment sales in the fourth quarter of 2002, which were restricted under the revolving credit/term loan facility for payment against its outstanding term loan.

Concentration Risk Financial instruments, which potentially expose the Company to concentrations of credit risk, consist primarily of cash, cash equivalents, restricted cash and accounts receivable. The Company maintains a significant portion of its cash and cash equivalents with several major financial institutions and creditworthy issuers. As of December 31, 2003, approximately 11 percent of the Company's accounts receivable are with entities engaged in the energy industry. These industry concentrations 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. Receivables are generally not collateralized; however, the Company believes the credit risk posed by industry concentration is offset by the diversification and creditworthiness of its customer base of residential, commercial and industrial customers.

Our material power supply contracts and arrangements are principally with Hydro-Quebec and Vermont Yankee Nuclear Power Corporation. These contracts support about 90 percent of our total annual energy (mWh) purchases. These supplier concentrations could have a material impact on the Company's net power costs, if one or both of these sources were unavailable over an extended period of time.

Reclassifications The Company will record reclassifications to the financial statements of prior years when considered necessary or to conform to current-year presentation.

Recent Accounting Pronouncements
<u>Accounting and Disclosure Requirements for Guarantees:</u> In November 2002, FASB issued Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* ("FIN 45"). Beginning in 2003, this accounting standard requires that upon the issuance or modification of guarantees, the guarantor must recognize a liability for the fair value of the obligations it assumes under the guarantee. Liability recognition is required on a prospective basis for guarantees that are made or modified after December 31, 2002. There are also certain disclosure requirements under FIN 45. This Interpretation did not impact the Company's financial position or results of operations.

<u>Variable Interest Entities</u>: In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities* ("FIN 46") and in December 2003 the FASB issued its revision which addressed the requirements for consolidating certain variable interest entities ("VIE"). This interpretation clarifies the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," and replaces the current accounting guidance relating to the consolidation of certain special purpose entities. FIN 46 requires identification of the Company's participation in variable interest entities established on the basis of contractual, ownership or other monetary interests. A VIE is defined as an entity in which the equity investors do not have a controlling interest and the equity investment at risk is insufficient to fund future activities to permit the VIE to operate on a stand alone basis without receiving additional financial support. It requires the primary beneficiary of a variable interest entity to consolidate that entity. The Company does not expect to consolidate any existing interests in unconsolidated entities pursuant to requirements of FIN 46. The Company adopted Fin 46 at December 31, 2003 and does not have any VIE's.

<u>Derivative Instruments and Hedging Activities:</u> In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 Derivative Instruments and Hedging* Activities, which amends and clarifies accounting for derivative instruments under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* See further discussion in Derivative Financial Instruments above.

<u>Financial Instruments:</u> In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with the Characteristics of Both Liabilities and Equity.* This statement is effective for reporting periods after July 1, 2003 and establishes standards for classifying and measuring as liabilities certain financial instruments that embody obligations of the issuer and have characteristics of both liabilities and equity. Adoption of this statement did not impact the Company's financial position or results of operations.

Employers' Disclosures about Pensions and other Postretirement Benefits: In December 2003, the FASB revised SFAS No. 132, *Employers' Disclosures about Pensions and other Postretirement Benefits*," establishing additional annual disclosures about plan assets, investment strategy, measurement date, plan obligations and cash flows. The revised standard established interim disclosure requirements to the net periodic benefit cost recognized and contributions paid or expected to be paid during the current fiscal year. The new annual disclosures are effective for financial statements with fiscal years ending after December 15, 2003. The Company adopted the revised disclosure requirements as of December 31, 2003.

Medicare Prescription Drug, Improvement and Modernization Act of 2003: On January 12, 2004, the FASB issued FASB Staff Position No. FAS 106-1, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*, ("FSP No. 106-1") in response to a new law regarding prescription drug benefits under Medicare ("Medicare Part D") as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Currently, SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions,* ("SFAS No. 106") requires that changes in relevant law be considered in current measurement of postretirement benefit costs. Certain accounting issues related to the federal subsidy remain unclear and significant uncertainties may exist that impair a plan sponsor's ability to evaluate the direct effects of the new law and the ancillary effects on plan participants' behavior and healthcare costs. Due to these uncertainties, FSP No. 106-1 provides plan sponsors with an opportunity to elect to defer recognizing the effects of the new law in accounting for its retiree health care benefit plans under SFAS No. 106 and to provide related disclosures until authoritative guidance on accounting for the federal subsidy is issued and clarification regarding other uncertainties is resolved. The Company is evaluating the new law and the pending issuance of authoritative guidance and can not predict the effect, if any, on the Company's results of operations, financial position and financial statement disclosure. Therefore, measures of the accumulated postretirement benefit obligation or the net periodic postretirement benefit cost do not reflect the effects of the new law and issued guidance could require the Company to change previously reported information.

NOTE 2 - INVESTMENTS IN AFFILIATES

The Company's equity method investments are as follows (in thousands):

		December 31	
	Ownership	**2003**	2002
Vermont Yankee Nuclear Power Corporation (1)	58.85%	**$2,810**	$16,900
Vermont Electric Power Company, Inc. (2):			
Common stock	50.5%	**4,295**	4,079
Preferred stock	46.6%	**422**	502
Subtotal		**4,717**	4,581
Nuclear generating companies:			
Connecticut Yankee Atomic Power Company	2.0%	**943**	1,148
Maine Yankee Atomic Power Company	2.0%	**793**	1,052
Yankee Atomic Electric Company	3.5%	**40**	35
Subtotal		**1,776**	2,235
Total Investment in Affiliates		**$9,303**	**$23,716**

(1) On November 7, 2003, the Company's ownership percentage changed from 33.23 percent to 58.85 percent. Previously, in the first quarter of 2002, its ownership percentage changed from 31.3 percent to 33.23 percent. See discussion below for more detail.

(2) The Company's common stock ownership (voting and non-voting) changed from 56.8 to 50.6 percent in the third quarter of 2002, and from 50.6 percent to 50.5 percent in the third quarter of 2003. See discussion below for more detail.

On October 10, 2003, the PSB approved the Company's April 8, 2003 petition for approval to transfer its shares of Vermont Yankee to Custom Investment Corporation ("Custom"), a wholly owned passive investment subsidiary. The transfer was completed on October 10, 2003, and the transfer to Custom does not affect the Company's rights and obligations related to Vermont Yankee Nuclear Power Corporation. The Company may transfer its interests in Maine Yankee, Connecticut Yankee, Yankee Atomic, and Vermont Electric Power Company, to Custom in the future.

Vermont Yankee Nuclear Power Corporation ("Vermont Yankee") Summarized financial information is as follows (in thousands):

	December 31		
Earnings	**2003**	2002	2001
Operating revenues	**$187,123**	$175,722	$178,840
Operating income	**$668**	$6,949	$11,983
Net income	**$2,536**	$9,454	$6,119
Company's equity in net income	**$985**	$3,141	$1,912

	December 31	
Investment	**2003**	2002
Current assets	**$20,297**	$73,794
Non-current assets	**130,423**	127,632
Total Assets	**150,720**	201,426
Less:		
Current liabilities	**18,321**	22,642
Non-current liabilities	**127,625**	127,581
Net assets	**$4,774**	$51,203
Company's equity in net assets	**$2,810**	$16,900

Vermont Yankee sold its nuclear plant to Entergy Nuclear Vermont Yankee, LLC ("Entergy") on July 31, 2002. The sale agreement included a purchased power contract ("PPA"), which Vermont Yankee administers among the former plant owners and Entergy. Under the PPA between Entergy and Vermont Yankee, Vermont Yankee pays Entergy for generation at fixed rates; Vermont Yankee in turn bills the PPA charges from Entergy with certain residual costs of service through a FERC tariff to the Company and the other Vermont Yankee sponsors. Vermont Yankee's revenues shown in the table above include sales to the Company of $65.2 million in 2003, $60.2 million in 2002 and $56.1 million in 2001. Prior to the July 2002 sale, they were shown net of deferrals and amortizations in the Company's Consolidated Statements of Income.

On October 27, 2003, the Company received $14.3 million from Vermont Yankee related to the 2002 sale of the plant. Of that amount, return of capital amounted to approximately $13.7 million and cash dividends amounted to approximately $0.6 million. The sale resulted in a gain of about $0.1 million.

On November 7, 2003, Vermont Yankee completed the repurchase of shares held by certain non-Vermont sponsors. The non-Vermont sponsors remain obligated under all agreements with Vermont Yankee, including their power purchase obligations under the Vermont Yankee power contract with Entergy. The Company's ownership interest in Vermont Yankee increased from 33.23 percent to 58.85 percent as a result of the November 2003 repurchase of shares. Although the Company now owns a majority of the shares of Vermont Yankee, the Power Contracts, Sponsor Agreement and composition of the Board of Directors, under which Vermont Yankee operates, effectively restrict the Company's ability to exercise control over Vermont Yankee. Additionally, the Company has assessed its ownership interest in Vermont Yankee under the provisions of FIN 46 and concluded that it is not Vermont Yankee's primary beneficiary. Therefore, Vermont Yankee's financial statements have not been consolidated.

See Note 13 - Commitments and Contingencies, for additional information regarding the Company's long-term power contract with Vermont Yankee.

Vermont Electric Power Company, Inc. ("VELCO") Summarized financial information is as follows (in thousands):

Earnings	December 31 2003	2002	2001
Transmission revenues	**$23,107**	$20,257	$19,785
Operating income	**$5,533**	$5,091	$3,214
Net income	**$1,270**	$1,094	$1,118
Company's equity in net income	**$675**	$516	$585

Investment	December 31 2003	2002
Current assets	**$26,224**	$24,168
Non-current assets	**100,569**	83,635
Total assets	**126,793**	107,803
Less:		
Current liabilities	**58,824**	39,616
Non-current liabilities	**58,569**	58,991
Net assets	**$9,400**	$9,196
Company's equity in net assets	**$4,717**	$4,581

VELCO and its wholly owned subsidiary, Vermont Electric Transmission Company, Inc., own and operate transmission systems in Vermont over which bulk power is delivered to all electric utilities in the state. VELCO has entered into transmission agreements with the State of Vermont and electric utilities. Under these agreements, it bills all costs, including interest on debt and a fixed return on equity, to the state and others that use the system. These contracts enable VELCO to finance its facilities primarily through the sale of first mortgage bonds.

VELCO operates pursuant to the terms of the 1985 Four-Party Agreement (as amended) with the Company and two other major distribution companies in Vermont. Although the Company owns 50.5 percent of VELCO's outstanding common stock, the Four-Party Agreement does not provide the Company ability to exercise control over VELCO. Additionally, the Company assessed its ownership interest in VELCO under the provisions of FIN 46 and concluded that it is not VELCO's primary beneficiary. Therefore, VELCO's financial statements have not been consolidated. Included in VELCO's revenues shown above are transmission services to the Company (reflected as production and transmission expenses in the accompanying Consolidated Statements of Income) amounting to $10.7 million in 2003, $11.7 million in 2002 and $10.5 million in 2001.

The Company's common stock ownership (voting and non-voting) changed from 50.6 percent to 50.5 percent in the third quarter of 2003 and from 56.8 to 50.6 percent in the third quarter of 2002. The decrease in ownership percentage reflects acquisitions of non-voting common stock issued by VELCO in amounts below the Company's pro-rata ownership at the time of purchase. These acquisitions resulted from FERC's July 2002 approval of a joint request by the Company and GMP for each to purchase certain shares of non-voting Class C common stock issued by VELCO. This authorized VELCO to issue up to 16,170 shares of Class C common stock to provide working capital, maintain a debt-to-equity ratio within the guidelines of VELCO's Articles of Association, and realign equity ownership as close as possible to entitlement levels of VELCO's transmission services. In the third quarter of 2003, the Company acquired additional shares of VELCO's non-voting Class C common stock for approximately $0.2 million. In the third quarter of 2002, the Company acquired additional shares for approximately $0.5 million.

The Company received $0.1 million in 2003 and $0.2 million in 2002 related to the return of capital from VELCO's Class C preferred stock.

Nuclear Generating Companies The Company is one of several sponsor companies with ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. The Company is responsible for paying its ownership percentage of decommissioning and all other costs for each plant. These companies have permanently shut down generating activities and are conducting decommissioning activities. The Company also has a 1.7303 percent joint-ownership interest in Millstone Unit #3. Its obligations related to that plant are described in more detail in Note 13 - Commitments and Contingencies. The Company's obligations related to the eventual decommissioning of the Vermont Yankee plant ceased when the plant was sold to Entergy on July 31, 2002.

The Company's share of estimated future payments related to the decommissioning of Maine Yankee, Connecticut Yankee and Yankee Atomic, based on current forecasts for each plant, are as follows (dollars in millions):

	Date of Study	Total Obligation (a)	Remaining Obligation (b)	Revenue Requirements (c)	Company Share (d)
Maine Yankee	2003	$695.0	$220.7	$364.4	$7.4
Connecticut Yankee	2003	$1,004.7	$543.9	$666.4	$13.3
Yankee Atomic	2003	$667.3	$237.4	$181.3	$7.5

(a) Estimated total decommissioning cost for each plant in 2003 dollars.
(b) Estimated remaining decommissioning costs in 2003 dollars for the period 2004 through 2023 for Maine Yankee and Connecticut Yankee, and through 2022 for Yankee Atomic.
(c) Estimated future payments required by the Sponsor companies to recover estimated decommissioning and all other costs for 2004 and forward, in nominal dollars. For Maine Yankee and Connecticut Yankee includes collections for required contributions to spent fuel funds as described below. Yankee Atomic has already collected and paid these required contributions.
(d) Represents the Company's share of revenue requirements based on its ownership percentage in each plant. For Yankee Atomic, this includes $1.1 million related to 2003. See discussion below for more detail.

Maine Yankee, Connecticut Yankee and Yankee Atomic are seeking recovery of fuel storage related costs stemming from the default of the United States Department of Energy ("DOE") under the 1983 fuel disposal contracts that were mandated by the United States Congress under the High Level Waste Act. These damage claims are now pending in the Federal Court of Claims. The trial is expected to begin in July 2004. The fuel storage related costs associated with the damage claims are included in each company's estimated total obligation, shown in the table above. None of the plants have included any allowance for potential recovery of these claims in their estimates.

The Company's share of each plant's estimated revenue requirements are reflected on the Consolidated Balance Sheets as regulatory assets or other deferred charges, and nuclear decommissioning liabilities (current and non-current). At December 31, 2003, the Company had regulatory assets of about $7.4 million related to Maine Yankee and $3.0 million related to Connecticut Yankee. These estimated costs are being collected from the Company's customers through existing retail and wholesale rate tariffs. At December 31, 2003, the Company also had other deferred charges of about $10.3 million related to incremental dismantling costs for Connecticut Yankee and $7.5 million for Yankee Atomic. These amounts are not currently being collected from customers through existing rates. On October 29, 2003, the PSB approved an Accounting Order for treatment of these incremental costs as other deferred charges, to be addressed in its next rate proceeding. The Company will adjust the associated regulatory assets, other deferred charges and nuclear decommissioning liabilities when revised estimates are provided.

Maine Yankee: The Company has a 2 percent ownership interest in Maine Yankee. Costs billed by Maine Yankee are expected to change due to their October 21, 2003 filing at FERC. Maine Yankee's current billings to sponsor companies are based on their rate case settlement approved by FERC on June 1, 1999 under which costs were to be recovered through October 2008. In that settlement, Maine Yankee agreed to file a FERC rate proceeding with an effective date for new rates no later than January 1, 2004. In the current filing the cost recovery period is proposed to extend to 2010.

Connecticut Yankee: The Company has a 2 percent ownership interest in Connecticut Yankee. Costs currently billed by Connecticut Yankee are based on its most recent FERC-approved rates, which became effective September 1, 2000, for collection through 2007. These amounts are being collected from the Company's customers through existing rates.

Connecticut Yankee is involved in a contract dispute with Bechtel Power Corporation ("Bechtel"), which resulted in termination of the decommissioning services contract between Connecticut Yankee and Bechtel. This is a commercial contract dispute regarding Bechtel's performance; it is not related to safety, security or workmanship issues. As a result of contract termination, on July 14, 2003, Connecticut Yankee became the general contractor for the decommissioning.

On June 23, 2003, Bechtel responded to the notice of termination by filing a complaint for breach of contract, misrepresentation, and bad faith, in Connecticut Superior Court. After the contract termination, Bechtel amended its complaint to allege additional contract breaches (including wrongful termination) by Connecticut Yankee.

On August 22, 2003, Connecticut Yankee formally denied the allegations of Bechtel's amended complaint and filed a counterclaim. It alleges various material breaches of contract that justified Bechtel's termination, along with misrepresentation and bad faith. It also requests that Bechtel be found responsible for project costs in excess of Bechtel's unpaid contract balance, and for other damages. The lawsuit has been assigned to the Complex Litigation Docket and has been set for a jury trial beginning May 4, 2006. Connecticut Yankee also notified Bechtel's surety of its intention to file a claim under the performance bond.

At Connecticut Yankees' December 2003 Board of Directors meeting, the Board endorsed an updated estimate of the costs for the plant's decommissioning project. This updated cost estimate referred to as the "2003 Estimate" of approximately $823 million, covers the time period 2000 through 2023 and represents an aggregate increase of approximately $413 million in nominal dollars over the cost estimate in its 2000 FERC rate case settlement, which covered the same time period. It also includes increased costs from a November 2002 updated estimate which were related to projected costs of spent fuel storage, security, and liability and property insurance. The 2003 Estimate represents an increase of about $389 million in 2003 dollars. Prior to the approval of the cost estimate in the 2000 FERC settlement, Connecticut Yankee had also incurred about $184 million for decommissioning costs in the 1997 - 1999 timeframe.

The 2003 Estimate is still undergoing review; it reflects the fact that Connecticut Yankee is now directly managing the work (self performing) to complete decommissioning of the plant following the default termination of Bechtel as described above. Connecticut Yankee intends to update the estimate based on additional information when available including the results of competitive bidding of project work such as demolition. The 2003 Estimate does not include any allowance for relief of the Bechtel contract dispute or the DOE damage claim described above.

Connecticut Yankee is also beginning the preparation of a rate case application that is required to be filed with FERC by July 1, 2004 under the terms of its 2000 FERC rate case settlement. While Connecticut Yankee has not determined the relief it will seek in the forthcoming application, it anticipates that annual decommissioning collections would have to be increased significantly, beginning January 2005, to support anticipated project cash flow over the next several years and to fund long-term fuel storage through 2023.

The Company's estimated aggregate obligation related to Connecticut Yankee is about $13.3 million. The timing, amount and outcome of these filings cannot be predicted at this time. The Company believes its share of Connecticut Yankee's decommissioning costs are probable of recovery in future rate proceedings.

Yankee Atomic: The Company has a 3.5 percent ownership interest in Yankee Atomic. Billings to the Company ended in July 2000 based on Yankee Atomic's determination that it had collected sufficient funds to complete the decommissioning effort. The Company is not currently collecting Yankee Atomic costs in retail rates.

In late 2002, Yankee Atomic revised its cost estimate for decommissioning the plant, reflecting an increase of about $190 million over prior estimates utilized by FERC. The increase was attributable to increases in projected costs of spent fuel storage, security, and liability and property insurance. In April 2003, Yankee Atomic filed with FERC for new rates to collect these costs from sponsor companies. FERC approved the resumption of billings starting June 2003 for a recovery period through 2010, subject to refund. The Company expects its share of these costs will be recoverable in future rates. In 2003, Yankee Atomic's billings to the Company amounted to about $1.1 million. Based on a PSB-approved accounting order, the Company is deferring these costs.

NOTE 3 - NON-UTILITY INVESTMENTS

Catamount Catamount invests in unregulated energy generation projects in the United States and United Kingdom. As of December 31, 2003, Catamount has interests in nine operating independent power projects located in Rumford, Maine; East Ryegate, Vermont; Hopewell, Virginia; Rupert and Glenns Ferry, Idaho; Nolan County, Texas; Thetford, England; Thuringen, Germany and Mecklenburg-Vorpommern, Germany.

Eversant Eversant has a $1.4 million equity investment, representing a 12 percent ownership interest in The Home Service Store, Inc. ("HSS"), as of December 31, 2003. HSS has established a network of affiliate contractors who perform home maintenance repair and improvements for HSS members. Eversant accounts for this investment on a cost basis. In the third quarter of 2001, Eversant recorded a $1.2 million after-tax write-down of its investment in HSS to fair value based on an updated valuation at the time.

Certain financial information related to Catamount's investments in projects and Eversant's investment in HSS is provided in the table that follows (in thousands):

	Location	Generating Capacity	Fuel	In-Service Date	Ownership	Investment December 31 2003	Investment December 31 2002
Catamount Projects:							
Rumford Cogeneration	Maine	85 MW	Coal/Wood	1990	15.1%	**$16,122**	$18,682
Ryegate Associates	Vermont	20 MW	Wood	1992	33.1%	**4,220**	7,190
Appomattox Cogeneration	Virginia	41 MW	Coal/Biomass/ Black liquor	1982	25.3%	**2,429**	4,180
Rupert Cogeneration Partners	Idaho	10 MW	Gas	1996	50.0%	**342**	261
Glenns Ferry Cogeneration	Idaho	10 MW	Gas	1996	50.0%	**205**	76
Sweetwater Wind I LLC	Texas	37.5 MW	Wind	2003	30.50%	**6,212**	-
Fibrothetford Limited	England	38.5 MW	Biomass	1998	44.7%	**3,233**	2,807
DK Burgerwindpark Eckolstadt	Germany	14.3 MW	Wind	2000	10.0%	**451**	335
DK Windpark Kavelstorf GmbH&Co. KG	Germany	7.2 MW	Wind	2001	10.0%	**190**	145
Other	Various		Wind			**-**	50
Subtotal Catamount projects						**$33,404**	$33,726
Eversant Investment in HSS	Various in U.S.	n/a	n/a	n/a	12.0%	**$1,361**	$1,361
Total Non-Utility Investments						**$34,765**	**$35,087**

Catamount Operations

Catamount is primarily focused on developing, owning and operating wind energy projects, and has projects under development in the United States and the United Kingdom. Wind energy is competitive with other forms of electric generation and has low production costs compared to other renewable energy sources. Environmental and energy security concerns support growth in the wind sector. Catamount is currently pursuing the sale of certain of its interests in non-wind electric generating assets.

In the third quarter of 2003, the Company's consolidated federal income tax provision reflected a benefit of approximately $2.3 million primarily related to the proposed sale of Connecticut Valley's plant and franchise. Capital gain treatment on the proposed sale of Connecticut Valley (which closed January 1, 2004) allowed for a reduction of certain income tax valuation allowances at Catamount (Fibrothetford Limited $1.7 million, Glenns Ferry and Rupert $0.6 million), reflecting Management's best estimate that deferred income taxes for certain previously recorded equity losses will be realized.

Catamount incurred a loss of about $1.6 million in 2003, excluding the tax benefit described above. This compares to earnings of $1.5 million in 2002 and a loss of $8.7 million in 2001. Information regarding certain of Catamount's investments follows.

Glenns Ferry and Rupert Catamount is negotiating with a third party for the sale of its investment interests in Rupert and Glenns Ferry. Catamount cannot predict whether a sale will ultimately be consummated. Previously, in the fourth quarter 2001, Catamount recorded after-tax impairment charges of $3 million for all of its interests in the Rupert and Glenns Ferry projects due to the deteriorating financial condition of the projects' steam hosts essential to the projects' Qualifying Facility status and long-term viability.

In May 2002, Rupert and Glenns Ferry were issued an Events of Default notice by their lender. Steam host restructurings in 2002 cured most of the events of default identified. Rupert cured its remaining events of default in March 2003 and management anticipates that Glenns Ferry will cure its remaining events of default by the end of 2004. Management does not believe this will have a material impact on Catamount.

Sweetwater 1 On June 30, 2003, Catamount entered into an equity commitment for up to a $10.1 million equity investment in the 37.5-MW wind farm in Nolan County, Texas known as Sweetwater 1. The project's financial advisor located an additional equity investor for the project, reducing Catamount's equity commitment. In December 2003, Catamount acquired its equity interest in Sweetwater 1 for $6.2 million.

Fibrothetford Limited Catamount had a Sale and Purchase Agreement with a third party for the sale of its Fibrothetford investment interests. In July 2003, the buyer suspended the sale and in December 2003, Catamount terminated the Sale and Purchase Agreement. The buyer is still interested in acquiring Catamount's investment interests, but Catamount cannot predict whether a sale will ultimately be consummated.

To the extent required, continuing equity losses are applied as a reduction to Catamount's note receivable balance from Fibrothetford. In 2003, Catamount reserved approximately $2 million against interest income on the note receivable. Previously, in the fourth quarter of 2001, Catamount recorded an after-tax impairment charge of $3.2 million and a valuation allowance for the $2.2 million deferred tax asset. The impairment charge was based on the expected market value of Catamount's interest given the project's financial condition at the time.

Heartlands Power Limited and Gauley River In the fourth quarter of 2002, Catamount sold its interest in Heartlands Power Limited and Gauley River. The proceeds from the sales approximated the net book value of its investments in both projects. Also, in the third quarter of 2002, Catamount recorded after-tax impairment charges of $1.3 million related to Heartlands and $0.8 million related to Gauley River. At the time, the 2002 impairment charges were related to the pending sale of Heartlands, and funding requirements as a condition of the Gauley River Purchase and Sale Agreement. In 2001, Catamount recorded an after-tax impairment charge of $1.4 million related to Gauley River based on bids received from third parties, less estimated costs to sell.

Eversant Operations

In addition to its HSS investment described above, Eversant's wholly owned subsidiary, SmartEnergy Water Heating Services, Inc. ("SEWHS"), engages in the sale or rental of electric water heaters in Vermont and New Hampshire. SEWHS had earnings of $0.5 million in 2003, $0.3 million in 2002 and $0.4 million in 2001.

During 2001, AgEnergy (formerly SmartEnergy Control Systems), a wholly owned subsidiary of Eversant, filed a claim in arbitration against Westfalia-Surge, the exclusive distributor that marketed and sold its SmartDrive Control product. The arbitration concerned AgEnergy's claim that Westfalia-Surge had not conducted itself in accordance with the exclusive distributorship agreement between the parties. On January 28, 2002, AgEnergy received an adverse decision related to the arbitration. On November 6, 2002, Westfalia filed a Petition to Confirm the Arbitrator's Award, which effectively sought to expand the Arbitrator's Award. AgEnergy sought dismissal of the Petition to the extent it sought costs in excess of those established by the Arbitrator. The Petition was dismissed for lack of jurisdiction.

Overall, Eversant's 2003 earnings were $0.5 million, versus net losses of $0.5 million in 2002 and $2.1 million in 2001. In early 2002, the Company decided to discontinue Eversant's efforts to pursue unregulated business opportunities except for SEWHS.

NOTE 4 - DISCONTINUED OPERATIONS - CONNECTICUT VALLEY SALE

On December 5, 2002, the Company agreed to sell Connecticut Valley's franchise and plant assets to PSNH. The agreement resulted from months of negotiations with the Governor's Office of Energy and Community Services, NHPUC staff, the Office of Consumer Advocate, the City of Claremont and New Hampshire Legal Assistance. The sale was intended to resolve all Connecticut Valley restructuring litigation in New Hampshire and the Company's stranded cost litigation at FERC.

Under the terms and conditions of the sale agreements, PSNH would pay to Connecticut Valley for Connecticut Valley's franchise, plant assets and related items, the net book value of the assets, which approximates $9 million, plus $21 million as provided in the agreements. PSNH would acquire Connecticut Valley's poles, wires, substations and other facilities, and several independent power obligations, including the Wheelabrator contract.

On January 31, 2003, Connecticut Valley, the Company, PSNH and various other parties asked the NHPUC to approve settlements and transactions related to the sale. On May 23, 2003, the NHPUC approved the sale without conditions. In its order, the NHPUC also approved the settlement with Wheelabrator. On September 30, 2003, FERC issued an order authorizing the sale of Connecticut Valley's jurisdictional facilities to PSNH. On October 2, 2003, FERC issued an order approving an Offer of Settlement to permit termination of the wholesale power contract and related exit fee proceedings upon completion of the sale.

On January 1, 2004, Connecticut Valley completed the sale of substantially all of its plant assets and its franchise to PSNH. The sale resolved all Connecticut Valley restructuring litigation in New Hampshire and the Company's stranded cost litigation at FERC. PSNH paid Connecticut Valley approximately $30 million as described above. In return, PSNH acquired Connecticut Valley's poles, wires, substations and other facilities, and several independent power obligations, including the Wheelabrator contract. See FERC Exit Fee Proceedings below for additional information.

The sale will result in a pre-tax gain of approximately $5 million to $7 million which will be recorded in the first quarter of 2004. The gain, net of reserves, is related to the difference between expected sales revenue for the power that was formerly sold to Connecticut Valley and estimated sales revenue at market rates, for the years 2004 through 2015 (which represents the estimated life of the power contracts that were in place to source the wholesale power contract between the Company and Connecticut Valley). The Company will evaluate a long-term sale of the majority of power previously sold to Connecticut Valley to limit future market price variability.

The assets and liabilities of Connecticut Valley are classified as held for sale on the accompanying Consolidated Balance Sheets, in accordance with SFAS No. 144, and its results of operations are reported as discontinued operations for all periods presented in the accompanying Consolidated Income Statements. For presentation purposes, certain of the Company's common corporate costs, which were previously allocated to Connecticut Valley, have been reallocated back to continuing operations to reflect the impact of the sale on continuing operations. These common costs amounted to about $1.3 million in 2003, $1.4 million in 2002 and $1.2 million in 2001, on an after-tax basis. We began to present Connecticut Valley as discontinued operations in the second quarter of 2003 based on the NHPUC's approval of the sale. Previously, Connecticut Valley was reported as a separate segment.

As a wholly owned subsidiary of the Company, Connecticut Valley's results of operations may not be representative of a stand-alone company. Summarized financial information related to Connecticut Valley, including the reallocation of certain corporate common costs, reflecting Management's best estimate of impacts of the Connecticut Valley sale, are shown in the tables below.

Summarized results of operations of the discontinued operations are as follows (in thousands):

	December 31		
	2003	2002	2001
Operating revenues	**$19,728**	$20,242	$20,738
Operating expenses			
Purchased power	**14,725**	15,283	15,201
Other operating expenses	**2,049**	1,989	2,038
Income tax expense	**1,232**	1,224	1,289
Total operating expenses	**18,006**	18,496	18,528
Operating income	**1,722**	1,746	2,210
Other income (expense), net	**(276)**	(203)	(557)
Net income from discontinued operations, net of taxes	**$1,446**	$1,543	$1,653

The major classes of Connecticut Valley's assets and liabilities reported as held for sale on the Consolidated Balance Sheets are as follows (in thousands):

	December 31	
	2003	2002
Assets		
Net utility plant	**$9,251**	$9,164
Other current assets	**41**	78
Total assets held for sale	**$9,292**	$9,242
Liabilities		
Accounts payable	**$1,749**	$2,237
Short-term debt (a)	**3,750**	3,750
Total liabilities of assets held for sale	**$5,499**	$5,987

(a) Related to a Note Payable to the Company and reported as Notes Receivable on the Consolidated Balance Sheets. The Note was paid on January 1, 2004.

FERC Exit Fee Proceedings On February 28, 1997, the NHPUC told Connecticut Valley to stop buying power from the Company. In June 1997, the Company asked for FERC approval for a transmission rate surcharge to recover stranded costs if Connecticut Valley canceled the rate schedule. In December 1997, FERC rejected the proposal, but said it would consider an exit fee if the contract was canceled. A rehearing motion was denied, so the Company applied for an exit fee totaling $44.9 million as of December 31, 1997.

On April 24, 2001, a FERC Administrative Law Judge ("ALJ") issued an Initial Decision, ruling that if Connecticut Valley terminated its wholesale contract and became a wholesale transmission customer of the

Company, Connecticut Valley must pay stranded costs to the Company. The ALJ calculated the stranded cost payment at nearly $83 million through 2016. The exit fee would decrease annually if service continued, and would be recalculated if the wholesale contract ended.

On October 29, 2002, the Company and NHPUC asked FERC to withhold its final exit fee order so the parties could continue negotiating a settlement. The Connecticut Valley sale, described in detail above, would make the FERC decision moot. On October 2, 2003, FERC issued an order approving an Offer of Settlement to permit termination of the wholesale power contract and related exit fee proceedings upon completion of the sale.

Absent the sale, if Connecticut Valley had to end its contract with the Company and no exit fee was approved, the Company would have had to recognize a pre-tax loss of about $27.4 million as of December 31, 2004 (the earliest date that termination could occur under the rate schedule). Additionally, the Company would have had to write-off approximately $0.6 million pre-tax of regulatory assets.

The January 1, 2004, sale of Connecticut Valley's plant assets and franchise to PSNH, and Connecticut Valley's $21 million payment to the Company to terminate the wholesale power contract resolved this FERC litigation.

Wheelabrator Power Contract Connecticut Valley purchased power from several independent power producers, which own qualifying facilities as defined by the Public Utility Regulatory Policies Act of 1978. In 2003 Connecticut Valley bought 38,700 mWh under long-term contracts with these facilities, 94 percent from Wheelabrator Claremont Company, L.P., ("Wheelabrator") which owns a trash-burning generating facility. Connecticut Valley had filed a complaint with FERC related to its concern that Wheelabrator had not been a qualifying facility since it began operation. FERC denied that complaint and later denied an appeal, so Connecticut Valley sought relief from the NHPUC. In April 2002 Connecticut Valley and other parties submitted a settlement to the NHPUC.

As a result of the January 1, 2004 sale described above, PSNH acquired Connecticut Valley's independent power obligations, including the Wheelabrator contract, thus resolving this issue.

NOTE 5 - RECONCILIATION OF NET INCOME AND AVERAGE SHARES OF COMMON STOCK

A reconciliation of net income to net income available for common stock and average common shares outstanding basic to diluted follows (in thousands):

	Years Ended December 31		
	2003	2002	2001
Income from continuing operations	**$18,355**	$18,224	$754
Income from discontinued operations, net of tax	**1,446**	1,543	1,653
Income before preferred stock dividends	**19,801**	19,767	2,407
Preferred stock dividend requirements	**1,198**	1,528	1,696
Income available for common stock	**$18,603**	$18,239	$711
Average shares of common stock outstanding - basic	**11,884,147**	11,678,239	11,551,042
Dilutive effect of stock options	**124,791**	110,614	94,470
Dilutive effective of performance plan shares	**110,615**	153,969	134,723
Average shares of common stock outstanding - diluted	**12,119,553**	11,942,822	11,780,235

NOTE 6 - PREFERRED STOCK

The 8.3 percent Dividend Series Preferred Stock is redeemable at par through a mandatory sinking fund in the amount of $1 million per annum and, at its option, the Company may redeem at par an additional non-cumulative $1 million per annum. In the fourth quarter of 2003, the Company recorded $2 million in Restricted Cash related to a December 31, 2003 payment to the Transfer Agent for its $1 million mandatory sinking fund payment for 2004 and a $1 million optional payment. The payment to the Preferred Shareholders was made effective January 1, 2004. In the fourth quarter of 2002, the Company paid its $1 million mandatory sinking fund payment for 2003 and a $1 million optional payment. See Note 8 - Financial Instruments and Investment Securities for fair value information.

The Company's preferred and preference stock consisted of the following (dollars in thousands):

	2003	2002
Cumulative Preferred and Preference Stock		
Preferred stock, $100 par value, authorized 500,000 shares		
Outstanding:		
Non-redeemable		
4.15% Series; 37,856 shares	**$3,786**	$3,786
4.65% Series; 10,000 shares	**1,000**	1,000
4.75% Series; 17,682 shares	**1,768**	1,768
5.375% Series; 15,000 shares	**1,500**	1,500
Redeemable		
8.30% Series; 100,000 shares	**10,000**	10,000
Preferred stock, $25 par value, authorized 1,000,000 shares		
Outstanding - none	-	-
Preference stock, $1 par value, authorized 1,000,000 shares		
Outstanding - none	-	-
	18,054	18,054
Less current portion	**1,000**	-
Total cumulative preferred and preference stock	**$17,054**	$18,054

NOTE 7 - LONG-TERM DEBT AND SINKING FUND REQUIREMENTS

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

	2003	2002
First Mortgage Bonds:		
9.97%, Series HH, due 2003	-	$3,000
6.01%, Series MM, due 2003	-	7,500
6.27%, Series NN, due 2008	**$3,000**	3,000
6.90%, Series OO, due 2023	**17,500**	17,500
8.91%, Series JJ, due 2031	**15,000**	15,000
Second Mortgage Bonds:		
8.125%, due 2004	**75,000**	75,000
New Hampshire Industrial Development Authority Bonds		
5.5%, due 2009	**5,450**	5,450
Vermont Industrial Development Authority Bonds		
Variable, due 2013 (1.15% at December 31, 2003)	**5,800**	5,800
Connecticut Development Authority Bonds		
Variable, due 2015 (1.15% at December 31, 2003)	**5,000**	5,000
Other, various	**2,657**	21,537
	129,407	158,787
Less current portion	**2,657**	20,879
Total long-term debt	**$126,750**	$137,908

Utility Total utility long-term debt maturities and sinking fund requirements at December 31, 2003, amounted to $75 million related to the $75 million Second Mortgage Bonds, which mature on August 1, 2004. The Company is considering alternative refinancing arrangements. Currently, the Company intends to and has the ability to refinance the $75 million at maturity and therefore, this debt remains classified as long term. No payments are due on long-term debt for 2005 through 2007. Substantially all of the Company's utility property and plant is subject to liens under the First and Second Mortgage Bonds.

The Company extended $16.9 million of letters of credit expiring on November 30, 2004. These letters of credit support three series of Industrial Development/Pollution Control Bonds, totaling $16.3 million. These letters of credit are secured by a first mortgage lien on the same collateral supporting our First Mortgage Bonds.

The Company's long-term debt arrangements contain financial and non-financial covenants. At December 31, 2003, the Company was in compliance with all debt covenants related to its various debt agreements.

Dividend restrictions The indentures relating to long-term debt and the Articles of Association contain certain restrictions on the payment of cash dividends on capital stock. Under the most restrictive of such provisions, approximately $88 million of retained earnings was not subject to dividend restriction at December 31, 2003.

Under the Company's Second Mortgage Indenture, certain restrictions on the payment of dividends would become effective if the Company's Second Mortgage Bonds are rated below investment grade. Under the most restrictive of these provisions, all except approximately $5.8 million of retained earnings would be subject to dividend restrictions at December 31, 2003. In addition, Catamount has debt instruments in place that restrict the amount of dividends on capital stock that they are able to pay.

Non-Utility Catamount has a $25 million revolving credit/term loan facility and letters of credit, with $2.5 million outstanding at December 31, 2003. The facility expired on November 12, 2002 and on December 31, 2002, Catamount and its lender entered into the First Amendment to the facility that, among other things, extended the revolver facility for two more years. Under the two-year extension, Catamount can borrow against new operating projects subject to terms and conditions of the facility. The outstanding revolver loans were converted to amortizing loans on a two-year term-out schedule. The interest rate is variable, prime-based. Catamount's assets secure the facility. Catamount's long-term debt maturities, including its office building mortgage, total $2.7 million for 2004. Catamount's long-term debt contains financial and non-financial covenants. At December 31, 2003, Catamount was in compliance with all covenants under the credit facility.

In January 2004, Catamount paid off the outstanding $2.5 million on the term loan and in February 2004 Catamount notified the lender of its intent to terminate the credit facility. The termination is effective 90 days after notification to the lender. Catamount is now soliciting proposals from selected financial institutions for corporate and/or development credit facilities that will meet its business needs. Catamount cannot predict whether it will be able to ultimately solicit and enter into an appropriately priced corporate and/or development credit facility. The office building mortgage matures on April 15, 2004 and Catamount expects to pay the outstanding balance in full.

See Note 8 - Financial Instruments and Investment Securities for fair value of long-term debt.

NOTE 8 - FINANCIAL INSTRUMENTS AND INVESTMENT SECURITIES

The estimated fair values of the Company's financial instruments at December 31, 2003 and 2002 are as follows (in thousands):

	2003		2002	
	Carrying Amount	**Fair Value***	Carrying Amount	Fair Value*
Preferred stock not subject to mandatory redemption	**$8,054**	**$5,431**	$8,054	$4,931
Preferred stock subject to mandatory redemption	**$10,000**	**$12,618**	$10,000	$10,339
Long-term debt:				
First mortgage bonds	**$35,500**	**$41,513**	$46,000	$49,828
Second mortgage bonds	**$75,000**	**$77,325**	$75,000	$80,243
Other long-term debt	**$18,907**	**$19,411**	$37,787	$37,798

* Fair values are reported to meet disclosure requirements and do not necessarily represent the amounts at which obligations would be settled.

Cash, Receivables and Payables The carrying amounts of cash and cash equivalents, restricted cash, receivables and payables approximate fair value because of the short maturity of those instruments.

Preferred stock and long-term debt The fair value of the Company's fixed rate securities is estimated based on quoted market prices for the same or similar issues or on current rates offered to the Company for the same remaining maturation. Adjustable-rate securities are assumed to have a fair value equal to their carrying value.

Derivatives The estimated fair value of derivatives related to power contracts is based on quoted market information and appropriate modeling methodologies. Derivative instruments are recorded at fair value on the Consolidated Balance Sheets.

Life Insurance Investments Life insurance investments are held in a Rabbi Trust for the benefit of executive retirement plans. These life insurance policies are recorded at the net cash surrender value or fair value of $5.2 million at December 31, 2003 and $4.2 million for 2002, and are included in Investments and Other Assets in the Company's Consolidated Balance Sheets.

Millstone Decommissioning Trust Fund Decommissioning trust fund investments related to the Company's joint ownership interest in Millstone Unit #3 are recorded at year-end fair values of $4.3 million for 2003 and $3.7 million for 2002. The Company accounts for the decommissioning trust fund investments according to SFAS 115, *Accounting for Certain Investments in Debt and Equity Securities.* The fair value is adjusted by realized and unrealized gains and losses, with a corresponding decommissioning liability, which is included in Other in Deferred Credits and Other Liabilities on the Consolidated Balance Sheets. The decommissioning trust funds hold marketable debt and equity securities that are classified as Investments and Other Assets on the Consolidated Balance Sheets. Any appreciation on the trust fund is used to offset the related decommissioning liability. The fair value of these investments is summarized below (in thousands):

	2003	**2002**
Equity Securities	$3,175	$2,261
Debt Securities	1,105	1,332
Cash and other	60	66
Fair Value	$4,340	$3,659

Unrealized gains included in fair value amounted to about $0.8 million and $0.1 million in 2003 related to equity and debt securities, respectively. In 2002, unrealized gains amounted to about $0.2 million and $0.1 million related to equity and debt securities, respectively. In both years, unrealized losses included in fair value were not significant.

NOTE 9 - STOCK AWARD PLANS

The Company has awarded stock options to key employees and non-employee directors under various option plans approved in 1988, 1993, 1997, 1998, 2000 and 2002. The 2002 Long-Term Incentive Plan also authorizes the granting of stock appreciation rights, restricted shares and performance shares. Subject to adjustment for stock-splits and similar events, up to 1,646,875 shares of the Company's common stock may be awarded, including shares issued in lieu of or upon reinvestment of dividends arising from awards. Options are granted at the full market price of the common shares on the date of grant. The maximum term of an option may not exceed five years for non-employee directors and 10 years for key employees. Shares authorized and available for future grant under each plan and stock options outstanding at December 31, 2003 are shown in the table below.

Plan	Authorized	Available for Future Grant	Stock Options Outstanding
1988	334,375	-	24,000
1993	150,000	-	-
1997	350,000	49,640	147,560
1998	112,500	-	68,250
2000	350,000	28,750	219,150
2002	350,000	291,338	39,790
Total	1,646,875	369,728	498,750

Stock option activity during the past three years was as follows:

	2003	2002	2001
Options outstanding at January 1	**571,285**	494,585	518,485
Exercised	**(164,625)**	(28,700)	(98,550)
Granted	**111,865**	109,900	121,150
Expired/canceled	**(19,775)**	(4,500)	(46,500)
Options outstanding at December 31	**498,750**	571,285	494,585

Summarized information regarding stock options outstanding and exercisable at December 31, 2003:

		Weighted Average	
Range of Exercise Prices	Number Options	Remaining Contractual Life (Years)	Exercise Price
$10.5625 - $13.5625	158,410	4.4	$10.8589
$13.5626 - $16.2250	139,650	4.7	$15.2262
$16.2251 - $18.4375	114,540	8.9	$17.5264
$18.4376 - $19.0750	62,900	8.4	$19.0750
$19.0760 - $24.3125	23,250	3.4	$19.1800
	498,750		

The stock options granted during 2003 had a weighted-average grant date fair value of $2.25, compared to $3.57 in 2002 and $2.85 in 2001. The fair value was estimated using the Black Scholes model for 2003 and the binomial model for 2002 and 2001, with the following weighted-average assumptions:

	2003	2002	2001
Volatility	.2204	.2548	.3328
Risk-free rate of return	3.12%	5.50%	5.75%
Dividend yield	5.74%	6.61%	7.42%
Expected life (years)	5.74	7.14	6.09

Restricted Stock Plans The Company has restricted stock plans in which common stock is granted to certain executive officers, key employees and non-employee directors. Recipients are not required to provide consideration to the Company under these plans, other than rendering service, and have the right to vote the shares and to receive dividends under the plans. The Company accounts for these stock plans under APB 25.

Under the Company's 1997 Restricted Stock Plan ("Restricted Plan"), the total market value of the shares, at grant date, is treated as deferred compensation and charged to expense over the applicable vesting period. Interim estimates of compensation expense are recorded at the end of each reporting period based on a combination of the then-fair market value of the stock and the extent or degree of compliance with the performance criteria. Restricted Plan stock expense was $136,538 in 2003, $134,229 in 2002 and $97,161 in 2001.

As part of the Company's Long-Term Incentive Plan, restricted performance shares of common stock have been awarded to executive officers under the 1999, 2000, 2001, 2002 and 2003 Performance Share Plans ("Performance Plan"). These awards vary from zero to two-times the number of conditionally granted shares based on the Company achieving certain financial goals over three-year performance cycles. The total market value of the shares is treated as deferred compensation and charged to expense on a quarterly basis over the respective performance cycles based on changes in market value, achievement of financial goals and changes in employment. The performance cycle for the 1999 plan was completed at the end of 2001. The 2000 cycle ended in 2002, and the 2001 cycle ended in 2003. Performance Plan stock compensation charged to expense was $834,469 in 2003, $1,009,896 in 2002 and $1,014,851 in 2001.

Shares issued under these plans were as follows:

	2003*	2002	2001
Shares issued	**20,189**	28,054	5,813
Average market value per share	**$18.61**	$16.70	$15.63
Shares forfeited	-	-	1,660
Average market value per share	-	-	$10.99

* Includes 15,547 shares awarded from the 2002 long-term incentive plan.

NOTE 10 - PENSION AND POSTRETIREMENT 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 at least a statutory minimum to a trust. The Company is not required by its union contract to contribute to multi-employer plans.

On January 1, 2002, the Pension Plan was amended to include enhanced early retirement reduction factors and death benefits for beneficiaries of deceased active participants. Assumed rates of retirement were updated to reflect expected experience. The Company also adopted the GAR 94 mortality table and a heavier withdrawal assumption, as well as the GAR 94 lump sum basis required by IRS Revenue Ruling 2001-62.

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 are at least age 55. The Company funds this obligation through a Voluntary Employees' Benefit Association and 401(h) Subaccount in its Pension Plan.

The Company records pension and other postretirement benefit costs in accordance with SFAS No. 87, *Employers' Accounting for Pensions,* and SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions.* Also, the Company follows SFAS No. 132, *Employers' Disclosures about Pensions and other Postretirement Benefits.*

Benefit Obligation and Plan Assets

The changes in benefit obligation and Plan assets were as follows (in thousands):

	At December 31			
	Pension Benefits		Postretirement Benefits	
	2003	2002	**2003**	2002
Change in Benefit Obligation				
Benefit obligation at beginning of year (January 1)	**$83,498**	$71,241	**$20,512**	$16,082
Service cost	**2,745**	2,337	**421**	331
Interest cost	**5,483**	5,354	**1,309**	1,153
Amendments	**-**	3,075	**-**	-
Actuarial loss	**4,194**	6,415	**6,071**	4,758
Benefits paid	**(4,415)**	(4,924)	**(2,048)**	(1,812)
Projected obligation as of measurement date (September 30)	**$91,505**	$83,498	**$26,265**	$20,512
Accumulated obligation as of measurement date (September 30)	**$75,379**	$67,262	**-**	-

	Pension Plan		Postretirement Benefits	
Change in Plan Assets	**2003**	2002	**2003**	2002
Fair value of plan assets at beginning of measurement date	**$54,291**	$65,629	**$4,026**	$909
Actual return on plan assets	**9,428**	(6,414)	**28**	10
Employer contributions*	**-**	-	**2,224**	4,919
Benefits paid*	**(4,415)**	(4,924)	**(2,048)**	(1,812)
Fair value of assets as of measurement date (September 30)	**$59,304**	$54,291	**$4,230**	$4,026

* Postretirement benefits include benefits paid from employer assets.

Benefit Obligation Assumptions Weighted average assumptions used to determine benefit obligations at measurement date (September 30) are shown in the table that follows. The 2003 weighted average assumptions for pension and postretirement benefits were used in determining the Company's related liabilities at December 31, 2003. Similarly, the 2002 weighted average assumptions were used in determining liabilities at December 31, 2002.

	Pension Benefits		Postretirement Benefits	
	2003	2002	**2003**	2002
Discount rates	**6.00%**	6.50%	**6.00%**	6.50%
Rate of increase in future compensation levels	**3.75%**	4.00%	**3.75%**	4.00%

For measurement purposes, a 12 percent and 11.5 percent annual rate of increase in the per capita cost of covered health care benefits was assumed for fiscal 2004, for pre-65 and post-65 claims costs, respectively. The rate is assumed to decrease 1 percent in each of the subsequent years until the ultimate trend of 6 percent and 5.5 percent, respectively, 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:

	1-Percentage Point Increase	1-Percentage Point Decrease
Effect on postretirement benefit obligation as of September 30, 2003	$1,945,252	$(1,666,110)
Effect on total service and interest costs components for 2003	$120,647	$(101,523)

Asset Allocation

The asset allocations at the end of 2003 and 2002, and the target allocation for 2004, by asset category, are as follows:

Asset Category	Pension Plan			Postretirement Benefits		
	2004 Target	2003	2002	2004 Target	2003	2002
Equity securities	67.0%	66.8%	61.0%	67.0%	-	-
Debt securities	33.0	33.2	39.0	33.0	91.6%	-
Other	-	-	-	-	8.4%	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 Company's postretirement investment policy seeks to achieve sufficient funding levels to meet future benefit obligations to participants and minimize near-term cost volatility. During 2003, the majority of plan assets were invested in debt securities. The Company plans to invest 67 percent of plan assets in equity securities during 2004.

Fair Value The fair value of Pension Plan assets was $59,304,361 at the end of 2003 and $54,290,961 at the end of 2002, while the expected long-term rate of return was 8.25 percent in 2003 and 8.50 percent in 2002.

The fair value of postretirement benefit assets was $4,229,782 at the end of 2003 and $4,026,153 at the end of 2002, while the expected long-term rate of return was 8.25 percent in 2003 and 8.50 percent in 2002.

Funded Status

The Plans' funded status was as follows:

	Pension Plan		Postretirement Plan	
Reconciliation of funded status	**2003**	2002	**2003**	2002
Fair value of assets	**$59,304**	$54,291	**$4,230**	$4,026
Benefit obligation	**(91,505)**	(83,498)	**(26,265)**	(20,512)
Company contributions between measurement and year-end dates	**-**	-	**573**	652
Funded Status	**(32,201)**	(29,207)	**(21,462)**	(15,834)
Unrecognized net actuarial loss	**15,695**	14,973	**16,135**	10,629
Unrecognized prior service cost	**4,089**	4,483	**2**	-
Unrecognized net transition (asset) obligation	**(145)**	(291)	**2,303**	2,558
Accrued benefit cost	**$(12,562)**	$(10,042)	**$(3,022)**	$(2,647)

The amounts recognized in the Company's Consolidated Balance Sheets consisted of:

	Pension Plan		Postretirement Plan	
	2003	2002	**2003**	2002
Accrued benefit liability	**$(12,562)**	$(10,042)	**$(3,022)**	$(2,647)
Additional minimum liability	**(3,513)**	(2,929)	**-**	-
Intangible asset	**3,513**	2,929	**-**	-
Net amount recognized	**$(12,562)**	$(10,042)	**$(3,022)**	$(2,647)

Net Periodic Benefit Costs

Components of net periodic benefit costs were as follows:

	Pension Benefits			Postretirement Benefits		
	2003	2002	2001	**2003**	2002	2001
Net benefit costs include the following components						
Service cost	**$2,745**	$2,337	$2,138	**$420**	$331	$243
Interest cost	**5,483**	5,354	5,046	**1,309**	1,153	1,114
Expected return on plan assets	**(5,956)**	(6,493)	(6,244)	**(308)**	(243)	(102)
Amortization of prior service cost	**394**	295	191	**-**	-	-
Recognized net actuarial loss (gain)	**-**	(594)	(776)	**843**	416	135
Amortization of transition (asset) obligation	**(146)**	(146)	(146)	**256**	256	256
Supplemental adjustment for amortization of FAS 71 Regulatory asset (1997 VERP)	**-**	25	466	**-**	25	457
Accelerated amortization of FAS 71 Regulatory asset (1997 VERP)	**-**	-	441	**-**	-	431
Net periodic benefit cost	**$2,520**	778	1,116	**2,520**	1,938	2,534
Less amount allocated to other accounts	**423**	100	28	**423**	253	219
Net benefit costs expensed	**$2,097**	$678	$1,088	**$2,097**	$1,685	$2,315

Benefit Costs 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 2003, which were set at September 30, 2002, were used in determining 2003 expense. Likewise, the 2002 and 2001 weighted-average assumptions were used in determining 2002 and 2001 expense, respectively.

	Pension Benefits			Postretirement Benefits		
	2003	2002	2001	**2003**	2002	2001
Weighted average discount rates	**6.50%**	7.25%	7.25%	**6.50%**	7.25%	7.25%
Expected long-term return on assets	**8.25%**	8.50%	8.50%	**8.25%**	8.50%	8.50%
Rate of increase in future compensation levels	**4.00%**	4.50%	4.25%	**4.00%**	4.50%	4.25%

Expected Rate of Return on Plan Assets

The Company expects an annual long-term return for 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.

Based on the postretirement investment policy described above, the Company expects an 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 benefit and postretirement benefit expense for 2003 was based on an expected long-term return on assets rate of 8.25 percent. The same percentage will be used to determine the 2004 expense.

Pension Equity Adjustment Risk

Certain negative scenarios and unfavorable market conditions (asset returns are lower than expected, reductions in discount rates, and liability experience losses) may cause the Pension Plan's accumulated benefit obligation ("ABO") to exceed the fair value of Pension Plan assets as of the measurement date and would result in an unfunded minimum liability. If that occurs, and the minimum liability exceeds the accrued benefit cost, an additional minimum pension liability may be required to be recorded, net of tax, as a non-cash charge to Other Comprehensive Income, included in Common Stock Equity on the Consolidated Balance Sheet. The ABO represents the present value of benefits earned without considering future salary increases. The Company did not have a reduction in equity for the qualified Pension Plan for the year ended December 31, 2003 since the intangible asset, representing prior service costs and transition obligation, offset the additional minimum pension liability. Based on actual asset returns through December 31, 2003 and assuming all assumptions are met for the remainder of the measurement period through September 30, 2004, the Company does not anticipate a reduction in equity for the year ending December 31, 2004.

The Pension Plan currently meets the minimum funding requirements of the Employee Retirement Income Security Act of 1974. As such, in 2003 the Company was not required to make contributions to the Pension Plan, but will have funding requirements in 2004.

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 participants' share of the postretirement benefit cost funded by participant contributions. Of the benefits expected to be paid in 2004, about $4 million will be paid from the Pension Plan trust fund and about $1.9 million related to postretirement benefits will be paid from the Company's assets. Expected contributions reflect amounts expected to be contributed to funded plans. Information about the expected cash flows for the Pension Plan and postretirement benefit plans is as follows (in millions):

	Pension Benefits	Postretirement Benefits
Employer Contributions		
2004 (expected) to fund plan trusts & benefits*	$1.1	$1.4
Expected Benefit Payments		
2004	$4.0	$1.9
2005	4.7	2.0
2006	5.3	2.0
2007	5.9	2.1
2008	6.3	2.1
2009 - 2013	44.7	10.9

* Excludes expected benefit payments paid from employer assets for postretirement benefits.
The above amounts are for the calendar year, even though September 30 is the measurement date.

Other
Long-term Disability The Company provides post-employment long-term disability benefits. The accumulated year-end post-employment benefit obligations of $1.3 million in 2003 and $1.2 million in 2002 are reflected in the Company's Consolidated Balance Sheets as liabilities. The pre-tax post-employment benefit costs charged to expense, including insurance premiums, were $270,000 in 2003, $225,000 in 2002, and $271,000 in 2001.

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 matches employee pre-tax contributions up to 4 percent of eligible compensation after one year of service. Eligible employees are at all times 100 percent vested in their pre-tax and post-tax contribution account and in their matching employer contribution. The Company's matching contributions amounted to $1.1 million annually in 2003, 2002 and 2001.

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 was $3.3 million in 2003 and $3.1 million in 2002 is reflected in the Company's Consolidated Balance Sheets as a liability. The pre-tax SERP benefit costs charged to expense totaled $446,000 in 2003, $375,000 in 2002 and $493,000 in 2001.

NOTE 11 - INCOME TAXES
The components of federal and state income tax expense are as follows (in thousands):

	Years Ended December 31		
	2003	2002	2001
Federal:			
Current	**$10,040**	$8,583	$9,486
Deferred	**(3,627)**	438	(3,503)
Investment tax credits, net	**(379)**	(379)	(379)
	6,034	8,642	5,604
State:			
Current	**3,112**	2,439	2,738
Deferred	**(491)**	10	(1,126)
	2,621	2,449	1,612
Total federal and state income taxes	**$8,655**	$11,091	$7,216
Federal and state income taxes charged to:			
Operating expenses	**$10,125**	$11,009	$10,182
Other income	**(1,470)**	82	(2,966)
	$8,655	$11,091	$7,216

Total income taxes differ from the amounts computed by applying the statutory federal income tax rate to income before tax. The reasons for the differences are as follows (in thousands):

	Years Ended December 31		
	2003	2002	2001
Income before income tax	**$27,010**	$29,316	$7,970
Federal statutory rate	**35%**	35%	35%
Federal statutory tax expense	**9,454**	10,261	2,790
Increases (reductions) in taxes Resulting from:			
Dividend received deduction	**(499)**	(1,086)	(741)
Deferred taxes on plant	**(30)**	(30)	186
State income taxes net of federal tax benefit	**1,704**	1,592	1,048
Investment credit amortization	**(379)**	(379)	(379)
Equity method of accounting adjustment	**1,949**	-	-
AFUDC equity	**216**	216	214
Valuation allowance, net of related tax expense	**(3,430)**	257	3,985
Life insurance	**(364)**	318	183
Other	**34**	(58)	(70)
Total income tax expense provided	**$8,655**	$11,091	$7,216

SFAS No. 109, *Accounting for Income Taxes* ("SFAS No. 109"), requires recognition of deferred tax assets and liabilities for the future tax effects of temporary differences between carrying amounts and the tax basis of assets and liabilities. Under this method, deferred income taxes result from applying the statutory rates to the differences between the book and tax basis of asset and liabilities. Tax effects of temporary differences and tax carryforwards that give rise to significant portions of the deferred tax assets and deferred tax liabilities are presented below (in thousands):

	At December 31		
	2003	2002	2001
Deferred tax assets			
Equity investments	**$3,958**	$5,286	$4,200
Accruals and other reserves not currently deductible	**2,690**	3,148	2,085
Retiree medical benefits	**1,094**	1,062	1,465
Deferred compensation and pension	**7,326**	7,046	5,679
Environmental costs accrual	**2,973**	3,081	3,811
Millstone decommissioning costs	**1,794**	-	-
Contributions in aid of construction	**1,840**	1,813	1,656
Revenue deferral - mandated earnings cap	**1,331**	281	-
Long-term disability	**528**	474	488
Bad debt reserve	**476**	516	450
Capitalized development costs	**915**	564	1,122
Valuation allowance	**(811)**	(4,241)	(3,985)
Total deferred tax assets	**24,114**	19,030	16,971
Deferred tax liabilities			
Property, plant and equipment	**41,848**	40,511	41,719
Equity investments	**7,258**	9,363	8,108
Net regulatory asset	**2,379**	2,501	2,777
Conservation and load management expenditures	**214**	102	1,890
Vermont Yankee fuel rod maintenance	**1,282**	1,593	-
Vermont Yankee sale	**5,292**	5,082	-
Nuclear refueling costs	**45**	315	1,076
Millstone decommissioning costs	**1,453**	-	-
Other	**1,056**	1,329	229
Total deferred tax liabilities	**60,827**	60,796	55,799
Net deferred tax liability	**36,713**	$41,766	$38,828

Valuation Allowances 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. From January 1, 2003 to December 31, 2003, the valuation allowance decreased by about \$3.4 million. All other deferred income taxes are expected to be realized. The \$3.4 million decrease is related to the following:

- In the third quarter of 2003, Management determined that the Connecticut Valley sale agreement was more likely than not to occur, which afforded the Company the opportunity to realize capital gains on the sale. The capital gains treatment allowed for a \$2.3 million reduction of certain tax valuation allowances at Catamount. These tax valuation allowances were primarily related to previously recorded equity losses resulting from fourth quarter 2001 asset impairments charges taken at Catamount for certain of its investments. At that time, the Company had determined that it was more likely than not that current or future income tax benefits would not be realized for these asset impairment charges, and it was Management's best estimate that it would not realize enough capital gains to offset the potential capital losses resulting from the asset impairment charges.
- In the third quarter of 2003, the Company reduced the valuation allowance and corresponding deferred tax asset by about \$1.9 million due to the reclassification of an equity method of accounting adjustment related to the financial statements from one of Catamounts foreign projects. This reclassification did not impact 2003 earnings.
- During 2003 additional valuation allowances of about \$0.8 million were established for certain foreign losses related to Catamount's foreign investments. Management determined that it is more likely than not that a current or future income tax benefit would not be realized.

NOTE 12 - RETAIL RATES

The Company recognizes adequate and timely rate relief is required to maintain its financial strength, particularly since Vermont law does not allow power and fuel costs to be passed to consumers through fuel adjustment clauses. The Company will continue to review costs and request rate increases when warranted.

Vermont Retail Rates The Company's current retail rates are based on a June 26, 2001 PSB Order approving a settlement with the DPS, including a 3.95 percent rate increase effective July 1, 2001. As part of the settlement, the Company also agreed to a \$9 million write-off (\$5.3 million after-tax) of regulatory assets and a rate freeze through January 1, 2003. The order also ended uncertainty over Hydro-Quebec cost recovery by providing full cost recovery, made the January 1, 1999 temporary rates permanent, allowed the Vermont utility a return on common equity of 11 percent for the year ending June 30, 2002 (capped through January 1, 2004), and created new service quality standards. Lastly, the rate order requires the Company to return up to \$16 million to ratepayers if there is a merger, acquisition or asset sale that requires PSB approval.

On April 15, 2003, in accordance with the PSB's approval of the Vermont Yankee sale, the Company filed Cost of Service Studies for rate years 2003 and 2004 to determine whether a rate decrease is appropriate in either year. On July 11, 2003, the Company and DPS signed a Memorandum of Understanding ("MOU") regarding the Company's rates and allowed return on equity through the end of 2005, subject to a prior rate change. The MOU is subject to approval by the PSB, and provides, among other things, the following:

- Rate Stability - The DPS and the Company agreed that a change in the Company's rates in 2003 and 2004 is not warranted as a result of the Vermont Yankee sale. The Company agreed not to file for a rate increase for rates effective prior to January 1, 2005, subject to the Company's need for an emergency rate increase under certain circumstances.
- Earnings Cap - The MOU required the Company to reduce its current 11.00 percent allowed return on equity to 10.50 percent effective July 1, 2003. If the Company earns more than 10.75 percent in 2003, or 10.50 percent in either 2004 or 2005, any excess earnings would be applied to reduce deferred debits as approved by the PSB. The MOU required the Company to file a report detailing its "core return on equity" for 2003 and 2004 on March 1 of each of the following years.
- Redesign of Rates - Within 60 days of the PSB's approval of the MOU, the Company agreed to file with the PSB a fully allocated cost of service study and a proposed rate redesign.
- Alternative Regulation Plan - The Company and the DPS agreed to work cooperatively to develop and propose an alternative regulation plan by March 31, 2004. The MOU does not compel a filing of a plan absent agreement by the Company.

In July 2003, the PSB opened a Docket to review the MOU. A prehearing conference was held on September 30, 2003 and hearings commenced in December 2003. On January 27, 2004, the PSB issued its Order providing conditional approval for the MOU. Specifically, the Order provides that the MOU is approved, but only if the Company and DPS agree to the following modifications and conditions:

- A requirement that the allowed return on equity of 10.5 percent established under the MOU, to be effective as of July 1, 2003, be reduced to 10.25 percent with attendant changes to the earnings cap called for under the MOU;
- A requirement that beginning January 1, 2004, the Company recognize new amortizations of deferred charges currently on the balance sheet of approximately $2.5 million annually; and
- A requirement that within 30 days, the Company file with the PSB a proposal for applying the $21 million payment it received from PSNH to write down deferred charges. The proposal must either provide for an immediate $21 million write down, or explain why a more gradual write down is appropriate and provide the most rapid write-down that is practical.

The MOU and PSB Order are not binding on the Company. On February 3, 2004, the Company filed a Request for Reconsideration and Clarification. On February 12, 2004, the Company filed information with the PSB in response to PSB information requests. The Company has been advised that the PSB will schedule a workshop in March 2004 to review the Company's filing. The MOU and related Request for Reconsideration and Clarification are still in the regulatory process and the Company cannot predict the outcome of that process at this time.

New Hampshire Retail Rates Connecticut Valley's retail rate tariffs, approved by the NHPUC, contain a Fuel Adjustment Clause ("FAC") and a Purchased Power Cost Adjustment ("PPCA"). Under these clauses, Connecticut Valley recovers its estimated annual costs for purchased energy and capacity, which are reconciled when actual data is available.

On December 20, 2002, the NHPUC approved Connecticut Valley's fuel and purchased power rates for 2003, and on December 30, 2002, the Commission approved a Business Profits Tax Adjustment Percentage for 2003. Rates increased 8.5 percent on January 1, 2003.

On April 16, 2003, the NHPUC approved Connecticut Valley's request for an Interim PPCA to reduce a potential over-collection during the remainder of 2003. As a result, Connecticut Valley's rates decreased 6.3 percent beginning May 1, 2003.

On January 1, 2004, Connecticut Valley completed the sale of substantially all of its plant assets and its franchise to PSNH. As such, Connecticut Valley did not file to change its annual FAC, PPCA and Business Profits Tax Adjustment as it had done in the past. See Note 4 - Discontinued Operations - Connecticut Valley Sale.

NOTE 13 - COMMITMENTS AND CONTINGENCIES

Nuclear Investments The Company has a 2 percent equity ownership in Maine Yankee, 2 percent equity ownership in Connecticut Yankee and 3.5 percent equity ownership in Yankee Atomic, all of which are permanently shut down and are currently conducting decommissioning activities. The Company is responsible for paying its equity ownership percentage of decommissioning costs for all three plants. See Note 2 - Investments in Affiliates for additional information. The Company is also responsible for its 1.7303 joint-ownership percentage of decommissioning costs for Millstone Unit #3 as explained in Joint Ownership below.

On July 31, 2002, the Vermont Yankee plant was sold to Entergy, so the Company no longer bears the operating costs and risks associated with running the plant or the eventual decommissioning of the plant.

Nuclear Insurance: The Price-Anderson Act ("Act") currently limits public liability from a single incident at a nuclear power plant to approximately $10 billion. This protection consists of two levels. 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 retrospective premium, equal to its proportionate share of the excess loss, up to a maximum of $100.6 million per reactor per incident, limited to a maximum annual assessment of $10 million. The maximum assessment is adjusted at least every five years to reflect inflation. The Act has been renewed since it was first enacted in 1957, and expired in August 2002. Amendments to the Act were included in the Energy Policy Act of 2003, which was not passed. However, liability coverage purchased by existing commercial nuclear power plants under the Act is not affected by the expiration date. Currently, based on its joint-ownership interest in Millstone Unit #3, the Company could become liable for about $0.2 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. The Company's obligations under this Act for Vermont Yankee ended with the July 2002 sale of the plant.

Hydro-Quebec The Company is purchasing varying amounts of power from Hydro-Quebec under the Vermont Joint Owners ("VJO") Power Contract through 2016. The VJO includes a group of Vermont electric companies and municipal utilities, of which the Company is a participant. Related contracts were 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.

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 balance of the VJO participants, including the Company, will "step-up" to the defaulting party's share on a pro rata basis. As of December 31, 2003, the Company's obligation is approximately 46 percent of the total VJO Power Contract through 2016, which translates to approximately $734 million, on a nominal basis. The average annual amount of capacity that the Company will purchase from January 1, 2004 through October 31, 2012 is approximately 144.2 MW, with lesser amounts purchased through October 31, 2016.

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, the Company negotiated a third sellback arrangement whereby the Company received an effective discount on up to 70 MW of capacity starting in November 1995 for the 1996 contract year (declining to 30 MW in the 1999 contract year). In exchange for this sellback, Hydro-Quebec has the right upon four years' written notice, to reduce capacity deliveries by up to 50 MW beginning as early as 2009 until 2015. This option includes the use of a like amount of the Company's Phase I/II transmission facility rights. Hydro-Quebec can also exercise an option, upon one year's written notice, to curtail energy deliveries from an annual load factor of 75 to 50 percent due to adverse hydraulic conditions in Quebec. This can be exercised five times through October 2015. The Company has determined that the third sellback arrangement is a derivative. On April 11, 2001, the PSB approved an Accounting Order that requires that the change in a derivative's fair value be deferred on the balance sheet as either a deferred charge or deferred credit. At December 31, 2003, this derivative had an estimated fair value of approximately a $1.2 million unrealized loss. The estimated fair value is based on quoted market information and appropriate modeling methodologies.

Under the VJO Power Contract, the VJO can elect to change the annual load factor from 75 percent to between 70 and 80 percent five times through 2020, while Hydro-Quebec can elect to reduce the load factor to not less than 65 percent three times during the same period of time. The VJO contract runs through 2020, but the Company's schedules related to the contract end in 2016. The VJO has made three out of five elections to date, while Hydro-Quebec made its first election for the contract year beginning November 1, 2001 and the VJO elected to push the start of the 65 percent load factor to November 1, 2002. Hydro-Quebec made its second election of 65 percent load factor for the contract year beginning November 1, 2003. Hydro-Quebec has one such election remaining.

The following table is a summary of the Hydro-Quebec contracts including average annual projections for the calendar years as shown (dollars in thousands, except per kWh amounts):

	2003	Estimated Average 2004 - 2012	Estimated Average 2013 - 2016
Annual Capacity Acquired	142.8MW	144.2MW	(a)
Minimum Energy Purchase - annual load factor	65%	(b)	75%
Energy Charge	$22,275	$27,389	$21,380
Capacity Charge	35,251	34,454	22,844
Total Energy and Capacity Charge	$57,526	$61,843	$44,224
Average Cost per kWh	$0.070	$0.069	$0.072

(a) Annual capacity acquired is projected to be about 116 MW for 2013 through 2015 and 23 MW for 2016.
(b) Annual load factor is projected to be 65 percent for contract years ending October 31, 2004 and 2005, and 75 percent for contract years ending October 31, 2006 through 2012.

The Company's estimated cost of energy and capacity under the existing contracts with Hydro-Quebec, based on the load factors shown in the table above, are $58.2 million in 2004, $61.4 million in 2005, $62.1 million in 2006, $62.5 million in 2007 and $63.3 million in 2008.

Vermont Yankee The Company has a 35 percent entitlement in Vermont Yankee output sold by Entergy to Vermont Yankee, through a long-term power purchase contract with Vermont Yankee. One remaining secondary purchaser continues to receive a small percentage of the Company's entitlement. The long-term contracts between Vermont Yankee and the Company and between Vermont Yankee and Entergy became effective on July 31, 2002, the same day that the Vermont Yankee nuclear plant was sold to Entergy. The Company is responsible for the purchase of replacement power to the extent required to serve its load when the plant is not operating due to scheduled or unscheduled outages.

The purchased power contract ("PPA") in which Vermont Yankee purchases power from Entergy and in turn sells to the Company and other parties includes prices that generally range 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" that protects the current Vermont Yankee entitlement holders, including the Company and its power consumers, if power market prices drop significantly. If the market prices rise, however, contract prices are not adjusted upward. The PPA is expected to result in decreased costs over the life of the PPA when compared to continued ownership of the plant.

A summary of the Company's estimated purchases of Vermont Yankee output under PPA follows (dollars in thousands, except per kWh amounts):

	2003	Estimated Average 2004 - 2012
Capacity acquired	182 MW	182 MW
Company share of plant output	34.8269%	34.8269%
Annual energy charge per mWh	$42.00	$41.80
Average cost per mWh	$42.38	$42.30
Contract period		March 2012

In 2003, the Company's Vermont Yankee purchases were about $65.2 million based on its entitlement share of plant output. Future purchases are expected to be $62.8 million in 2004, $57.7 million in 2005, $60.7 million in 2006, $57.9 million in 2007 and $59.2 million in 2008.

Vermont Yankee Operations: Vermont Yankee's next scheduled refueling outage begins in April 2004. In December 2003 the Company entered into a forward purchase contract for replacement power related to that outage. The previous scheduled refueling outage occurred in October 2002, and was completed within 21 days. Prior to that, Vermont Yankee had a 12-day mid-cycle outage starting May 11, 2002 in order to repair defective fuel rods. Based on an approved Accounting Order, in 2002 the Company deferred approximately $3.9 million, representing its share of the costs for the repair, including incremental capacity and replacement energy costs. In 2003, that deferral was decreased by about $1.0 million related to a refund for the defective fuel rods.

In 2003, Entergy sought PSB approval to increase generation at the Vermont Yankee plant by an additional 110 MW. On November 5, 2003, the DPS announced that it had agreed to support Entergy's proposed uprate including Entergy's agreement to provide outage protection indemnification for the Company and GMP in the event that the uprate causes temporary outages that require the Vermont utilities to buy higher-cost replacement power. The outage protection coverage will be in place for three years, during which there may be uprate-related outages. The Company's right to indemnification is approximately $2.8 million. The agreement requires PSB approval and hearings began in January 2004. The Company cannot predict the outcome of this matter or how it might impact the future operations of Vermont Yankee.

Vermont Yankee Sale: Vermont Yankee completed the sale of its nuclear plant to Entergy on July 31, 2002. Events leading to PSB approval of the sale included:

- A March 6, 2002 Memorandum of Understanding reached between the Company, GMP, Entergy and DPS resolving issues raised earlier by the DPS.
- The PSB's June 13, 2002 Order approving the sale and the associated power purchase agreement between the owners and Entergy. In its Order, the PSB largely accepted the terms of the Memorandum of Understanding, but set several conditions including:
  - requiring that any money remaining in the decommissioning fund following completion of decommissioning be returned to consumers;

- requiring that the Company and GMP submit plans for using their share of any excess remaining in the decommissioning fund toward the development and use of renewable resources for Vermont;
- significant financial guarantees and corporate commitments from Entergy's parent corporation, ensuring the reliability of its subsidiaries' commitments;
- requiring the Company to file an updated cost-of-service and appropriate additional information as necessary in April 2003 to determine whether a rate decrease is appropriate in 2003 or 2004; and
- prohibiting Entergy from operating Vermont Yankee after March 31, 2012 without prior approval of the PSB.

- Requests by Entergy and the DPS in June 2002 for the PSB to amend its June 13 Order to allow 50-50 share with ratepayers for any excess remaining in the decommissioning trust fund.
- A July 22, 2002 agreement reached between Entergy and the utility owners of Vermont Yankee in which Vermont ratepayers will receive 100 percent of the Vermont utilities' share of any surplus remaining in the decommissioning fund when the plant is decommissioned. In return, the Company agreed to pay approximately $1 million in stockholder funds to the non-Vermont utility owners of the plant to provide parity for assigning their share of the decommissioning fund to Entergy.

All other regulatory approvals were granted on terms acceptable to the parties to the transaction, while certain intervener parties appealed the PSB approval to the Vermont Supreme Court. On July 25, 2003, the Court upheld the sale, rejecting the interveners' appeal.

In anticipation of the Vermont Yankee sale to Entergy, the Company sought and the PSB approved two Accounting Orders that allowed the Company to defer certain costs incurred in 2002 due to the sale. This included a deferral of approximately $5.3 million related to incremental costs associated with the sale including increased purchased power costs in 2002 under the PPA compared to costs if the Company had continued to own the plant, and a deferral of $2.9 million related to incremental income tax expense resulting from the sale of Vermont Yankee. In 2002, the Company also recorded the following after-tax items 1) a $0.6 million expense related to a shareholder payment to the non-Vermont owners of the plant in order to complete the sale, and 2) a $2.5 million favorable impact primarily due to state tax benefits available to Vermont Yankee as a result of the sale. There were no comparable items in 2003.

Independent Power Producers The Company receives power from several Independent Power Producers ("IPPs"). These plants use water, biomass and trash as fuel. Most of the power comes through a state-appointed purchasing agent, VEPP Inc. ("VEPPI"), which assigns power to all Vermont utilities under PSB rules. In 2003, the Company received 164,918 mWh under these long-term contracts, including 142,968 mWh received through VEPPI. These IPP purchases account for 6.2 percent of the Company's total mWh purchased and 11 percent of purchased power costs. Estimated purchases from IPPs are expected to be $18.8 million in 2004, $18.8 million in 2005, $18.5 million in 2006, $19.2 million in 2007 and $19.8 million in 2008. These amounts reflect annual savings of about $0.6 million related to the IPP settlement described below.

In 1999, the Company and 17 other Vermont utilities asked the PSB to make seven changes in the IPPs' contracts with the state purchasing agent, to reduce power costs for customers' benefit. The PSB opened an investigation, and three companies later dropped out of the case. Legal proceedings and negotiations continued until early 2002, when a settlement was filed with the PSB. The Company also agreed to jointly support efforts before the Vermont Legislature, resulting in the enactment of legislation to approve the use of securitization to buy down some of the IPPs' purchasing agent contracts. The Company believes that these efforts create the potential for more savings.

On January 15, 2003, the PSB issued a final order approving the settlement reached by the Company, other petitioning parties, the DPS and certain non-petitioning utility parties. The final settlement included proportional sharing of the cost savings among all Vermont electric utilities, and reimbursement of litigation costs by the non-petitioning companies. The PSB required that the parties make certain compliance filings, including final dispatch agreements for the Ryegate and Sheldon Springs facilities, and utility-specific plans for distributing savings to customers. All required filings were made by the parties and approved by the PSB in 2003.

Based on the settlement, nominal cost savings to all Vermont utilities are estimated between $8 million and $9 million between 2004 and 2014, exclusive of savings that might result from implementation of IPP contract buy downs through securitization. The Company should receive approximately 40 percent of the power savings credits made available under the settlement. Under the settlement, the power cost savings could not begin until a certificate of consent was issued by the IPPs indicating that all conditions required under the settlement were satisfied. In June 2003, the IPPs issued the required certificate, and VEPPI began passing along power cost savings to all Vermont utilities. The Company's share of the 2003 savings amounted to about $0.3 million, which is recorded as a regulatory liability to be addressed at the Company's next rate proceeding.

Joint-ownership 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. The Company has an external trust dedicated to funding its joint ownership share of future decommissioning for Millstone Unit # 3; these funds are described in more detail in Note 8 - Financial Instruments and Investment Securities. Also see Note 1 - Summary of Significant Accounting Policies for discussion of Asset Retirement Obligations.

As a joint owner of the Millstone Unit #3 facility, in which Dominion Nuclear Corporation ("DNC") is the lead owner with about 93.47 percent of the plant joint-ownership, the Company is responsible for its share of nuclear decommissioning costs. Contributions to the Millstone Unit #3 Trust Fund have been suspended based on DNC's representation to various regulatory bodies that the Trust Fund, for its share of the plant, exceeded the Nuclear Regulatory Commission's minimum calculation required. The Company could choose to renew funding at its own discretion as long as the minimum requirement is met or exceeded.

The Company's ownership interests in jointly owned generating and transmission facilities are set forth in the following table and are recorded in the Company's Consolidated Balance Sheets (dollars in thousands):

			In Service	MW	December 31	
	Fuel Type	**Ownership**	**Date**	**Entitlement**	**2003**	2002
Wyman #4	Oil	1.78%	1978	11.0	**$3,367**	$3,347
Joseph C. McNeil	Various	20.00%	1984	10.6	**15,485**	15,453
Millstone Unit #3	Nuclear	1.73%	1986	20.0	**76,166**	76,143
Highgate Transmission Facility		47.35%	1985	N/A	**14,303**	14,167
					109,321	109,110
Accumulated depreciation					**52,161**	49,549
					$ 57,160	$ 59,561

Environmental Over the years, more than 100 companies have merged into or been acquired by the Company. At least two of the 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 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 coal tar deposits, Polychlorinated Biphenyl contamination and potential off-site migration, the Company conducted studies in the late 1980s and early 1990s to quantify the situation. Investigation has continued, including periodic groundwater monitoring, and the Company continues to work with the State of Vermont to develop a mutually acceptable solution.

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 on request of the State of New Hampshire. In 2001, New Hampshire said 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, including groundwater monitoring and controls, was approved. That plan is now in place.

Dover, New Hampshire, Manufactured Gas Facility In 1999, 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 with the Company the same day that it was subsequently sold to PSNH.

The Company agreed to non-binding mediation regarding liability. Lengthy mediation followed with numerous parties, including the New Hampshire Department of Environmental Services. A settlement with PSNH was reached, in which certain liabilities the Company might have had were assigned to PSNH in return for a cash payment. As a result, the Company reversed $1.7 million in environmental reserves in the second quarter of 2002.

As of December 31, 2003 and 2002, reserves of $7.2 million and $7.5 million are recorded on the Consolidated Balance Sheets, representing Management's best estimate of the cost to remedy issues at these sites. 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.

Leases and support agreements The Company participated with other electric utilities in the construction of the Phase I Hydro-Quebec interconnection transmission facilities in northeastern Vermont, which were completed at a total cost of about $140 million. Under a support agreement relating to the Company's participation in the facilities, the Company is obligated to pay its 4.55 percent share of Phase I Hydro-Quebec capital costs over a 20-year recovery period ending in 2006. The Company also participated in the construction of Phase II Hydro-Quebec transmission facilities constructed throughout New England, which were completed at a total cost of about $487 million. Under a similar support agreement, the New England participants, including the Company, contracted to pay their proportionate share of the total cost of constructing, owning and operating the Phase II facilities, including capital costs. The Company is obligated to pay its 5.132 percent share of Phase II Hydro-Quebec capital costs over a 25-year recovery period ending in 2015. These agreements meet the capital lease accounting requirements under SFAS No. 13, *Accounting for Leases*. All costs under these agreements are recorded as purchased transmission expense in accordance with the Company's ratemaking policies. Future expected payments will range from about $3.8 million to $2.7 million annually from 2004 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.

The Company's shares of the net capital cost of these facilities, totaling approximately $11.8 million, are classified in the accompanying Consolidated Balance Sheets as Utility Plant and Capital lease obligations (current and non-current).

Rental commitments of the Company under non-cancelable leases as of December 31, 2003 are considered minimal, as the majority of the Company's leases are cancelable after one year or less from lease inception. Total rental expense included in the determination of net income, consisting principally of vehicle and equipment rentals, was approximately $4.4 million in 2003, $4.5 million in 2002 and $4.2 million in 2001.

Catamount Catamount entered into Indemnity Agreements, dated December 21, 1995, with Amerada Hess Corporation (formerly Eastern Energy Marketing, Inc.), related to its investments in Rupert Cogeneration Partners Ltd. and Glenns Ferry Cogeneration Partners Ltd. (collectively the "Partnerships"). Amerada Hess supplies the Partnerships with natural gas and related transportation pursuant to the Gas Services Agreements ("Gas Agreements"). Amerada Hess also entered into a natural gas supply agreement with Talisman Energy Inc. to supply the natural gas for the Partnerships. Under the Firm Energy Supply Agreements between the Partnerships and Idaho Power Company ("IPCO"), Amerada Hess provided certain security interests to IPCO for liquidated damages in the event that non-performance by Amerada Hess or Talisman Energy Inc. under the Gas Agreements causes the Partnerships to permanently curtail electric power sales to IPCO. Pursuant to the Indemnity Agreements, Catamount will indemnify Amerada Hess for up to 50 percent of the liquidated damages associated with non-performance under the Gas Agreements. The liquidated damages are calculated based on the terms of the Firm Energy Supply Agreements. Catamount's estimated range of exposure under the Indemnity Agreements is between $0.8 million and $5.6 million, depending on the year a liquidated damage claim is made.

Catamount's wholly owned subsidiary, Equinox Vermont Corporation ("Equinox"), verbally agreed to indemnify Tractebel Power, Inc. for up to 33 percent of the cost in the event that the price of fuel for Ryegate Associates (the "Partnership") rises above the price cap guaranteed by Tractebel, Inc. to the Partnership's lender. The verbal indemnity is non-recourse to Catamount.

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 the financial position or the results of operations of the Company, except as otherwise disclosed herein.

Change of control The Company has management continuity agreements with certain officers that become operative upon a change in control of the Company. Potential severance expense under the agreements varies over time depending on several factors, including the specific plan for individual officers and officers' compensation and age at the time of the change of control.

NOTE 14 - SEGMENT REPORTING

The Company's reportable operating segments include: **Central Vermont Public Service Corporation ("CV")**, which engages in the purchase, production, transmission, distribution and sale of electricity in Vermont. Custom Investment Corporation is included with CV in the table below; **Catamount Energy Corporation ("Catamount")**, which invests in unregulated, energy generation projects in the United States and the United Kingdom, and **All Other,** which includes operating segments below the quantitative threshold for separate disclosure. These operating segments include 1) Eversant Corporation ("Eversant"), which engages in the sale or rental of electric water heaters through a subsidiary, SmartEnergy Water Heating Services, Inc., to customers in Vermont and New Hampshire; 2) 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, and 3) Catamount Resources Corporation, which was formed to hold the Company's subsidiaries that invest in unregulated business opportunities. Prior to January 1, 2003, Eversant was reported as a separate segment; it no longer meets the quantitative threshold, therefore, all prior period amounts have been restated in the table below.

The accounting policies of the operating segments are the same as those described in the summary of significant accounting policies. Intersegment revenues include revenues for support services, including allocations of software systems and equipment, to Catamount and Eversant. Due to the sale of Connecticut Valley's franchise and net plant assets as described in Note 4 - Discontinued Operations - Connecticut Valley, its results of operations are reported as discontinued operations and its assets are reported as held for sale in the segment table below.

The intersegment sales and services for each jurisdiction are based on actual rates or current costs. The Company evaluates performance based on stand-alone operating segment net income. Financial information by industry segment for 2003, 2002 and 2001 is as follows (in thousands):

	CV VT	Catamount Energy Corporation	All Other	Discontinued Operations	Reclassification and Consolidating Entries	Consolidated
2003						
Revenues from external customers	$306,014	$527	$1,908	-	$(2,435)	$306,014
Intersegment revenues	98	-	-	-	(98)	-
Depreciation and other (1)	21,428	69	172	-	(241)	21,428
Operating income tax expense (benefit)	10,125	(1,808)	325	-	1,483	10,125
Operating income (loss)	24,019	(2,425)	818	-	1,607	24,019
Equity income - utility affiliates (2)	1,801	-	-	-	-	1,801
Equity income - non-utility affiliates (3)	-	6,362	-	-	(6,362)	-
Other income, net	2,451	2,010	62	-	(248)	4,275
Interest expense, net	11,083	657	-	-	-	11,740
Income from continuing operations	17,102	736	517	-	-	18,355
Income from discontinued operations	-	-	-	$1,446	-	1,446
Investments in affiliates	9,303	-	-	-	-	9,303
Assets held for sale	-	-	-	9,292	-	9,292
Total assets	472,493	48,300	3,874	9,292	(2,640)	531,319
Construction and plant expenditures	14,959	-	-	531	(531)	14,959
2002						
Revenues from external customers	$294,390	$2,567	$2,002	-	$(4,569)	$294,390
Intersegment revenues	123	-	-	-	(123)	-
Depreciation and other (1)	13,426	77	207	-	(284)	13,426
Asset impairment charges (3)	-	2,774	-	-	-	2,774
Operating income tax expense (benefit)	11,009	1,376	(316)	-	(1,060)	11,009
Operating income (loss)	25,203	(6,551)	(1,014)	-	7,565	25,203
Equity income - utility affiliates (2)	3,909	-	-	-	-	3,909
Equity income - non-utility affiliates (3)	-	11,651	-	-	(11,651)	-
Other income, net	(281)	(1,012)	(19)	-	2,883	1,571
Interest expense, net	11,624	1,171	(336)	-	-	12,459
Income (loss) from continuing operations	17,128	1,541	(445)	-	-	18,224
Income from discontinued operations	-	-	-	$1,543	-	1,543
Investments in affiliates	23,716	-	-	-	-	23,716
Assets held for sale	-	-	-	9,242	-	9,242
Total assets	462,565	60,743	13,539	9,242	(5,240)	540,849
Construction and plant expenditures	13,885	-	-	557	(557)	13,885
2001						
Revenues from external customers	$292,900	$504	$2,404	-	$(2,908)	$292,900
Intersegment revenues	134	-	-	-	(134)	-
Depreciation and other (1)	15,458	57	318	-	(375)	15,458
Regulatory asset write-off (4)	9,000	-	-	-	-	9,000
Reversal of estimated loss on power contracts (5)	2,934	-	-	-	-	2,934
Asset impairment charges (3)	-	8,905	-	-	-	8,905
Investment write-down (3)	-	-	1,963	-	-	1,963
Operating income tax expense (benefit)	10,182	1,793	(1,462)	-	(331)	10,182
Operating income (loss)	25,179	(6,003)	(568)	-	6,571	25,179
Equity income - utility affiliates (2)	2,668	-	-	-	-	2,668
Equity income - non-utility affiliates (3)	-	6,079	-	-	(6,079)	-
Other income, net	(4,136)	(7,767)	(297)	-	(1,083)	(13,283)
Interest expense, net	12,231	1,009	570	-	-	13,810
Income (loss) from continuing operations	11,524	(8,700)	(2,070)	-	-	754
Income from discontinued operations	-	-	-	$1,653	-	1,653
Investments in affiliates	23,823	-	-	-	-	23,823
Assets held for sale	-	-	-	9,071	-	9,071
Total assets	462,430	58,266	4,852	9,071	(3,455)	531,164
Construction and plant expenditures	16,148	-	-	405	(405)	16,148

(1) Includes net deferral and amortization of nuclear replacement energy and maintenance costs (included in Purchased power) and amortization of conservation and load management costs (included in Other operation expenses) in the accompanying Consolidated Statements of Income.
(2) See Note 2 herein for CV's investments in affiliates.
(3) See Note 3 herein for CV's investment in non-utility affiliates.
(4) See Note 12 herein for CV's retail rates.
(5) Included in Purchased power in the accompanying 2001 Consolidated Statement of Income.

NOTE 15 - UNAUDITED QUARTERLY FINANCIAL INFORMATION

The following quarterly financial information is unaudited and includes all adjustments consisting of normal recurring accruals which are, in the opinion of Management, necessary for a fair statement of results of operations for such periods. All quarterly information reported for 2003 and 2002 have been restated to reflect the impact of discontinued operations. See Note 4 - Discontinued Operations - Connecticut Valley Sale for additional information related to the sale. The amounts included in the table below are in thousands, except per share amounts:

	Quarter Ended				12-Months Ended
	March	June	September	December	
2003					
Operating revenues	$79,476	$73,588	$73,839	$79,111	$306,014
Operating income	$6,841	$6,177	$5,528	$5,473	$24,019
Income from continuing operations	$4,600	$4,800	$4,545	$4,410	$18,355
Income from discontinued operations	359	295	380	412	1,446
Income available for common stock	$4,959	$5,095	$4,925	$4,822	$19,801
Earnings per share from continued operations - basic	$.36	$.38	$.36	$.35	$1.45
Earnings per share from discontinued operations - basic	.04	.02	.03	.03	.12
Earnings per share - basic	$.40	$.40	$.39	$.38	$1.57
Earnings per share from continued operations - diluted	$.35	$.38	$.35	$.34	$1.41
Earnings per share from discontinued operations - diluted	.04	.02	.03	.03	.12
Earnings per share - diluted	$.39	$.40	$.38	$.37	$1.53
2002					
Operating revenues	$74,209	$69,720	$73,428	$77,032	$294,390
Operating income	$6,777	$5,400	$8,777	$4,248	$25,203
Income from continuing operations	$4,455	$3,619	$5,507	$4,644	$18,224
Income from discontinued operations	330	356	348	508	1,543
Income available for common stock	$4,785	$3,975	$5,855	$5,152	$19,767
Earnings per share from continued operations - basic	$.35	$.28	$.44	$.37	$1.43
Earnings per share from discontinued operations - basic	.03	.03	.03	.04	.13
Earnings per share - basic	$.38	$.31	$.47	$.41	$1.56
Earnings per share from continued operations - diluted	$.34	$.27	$.43	$.36	$1.40
Earnings per share from discontinued operations - diluted	.03	.03	.03	.04	.13
Earnings per share - diluted	$.37	$.30	$.46	$.40	$1.53

Item 9. Changes in and disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures Data

The Company's disclosure controls and procedures are designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission.

Under the direction of the Company's Chief Executive Officer and Chief Financial Officer, Management evaluated the Company's disclosure controls and procedures as defined in Rules 13a - 15(e) or 15d - 15(e) as of December 31, 2003. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that (1) the Company's disclosure controls and procedures were effective as of December 31, 2003 in timely alerting them to internal information relating to the Company (including its consolidated subsidiaries) required to be included in reports filed or submitted by the Company to the Securities and Exchange Commission, and (2) there have been no changes in the Company's internal control over financial reporting that occurred during the quarter ended December 31, 2003, that materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting.

PART III

Item 10. Directors and Executive Officers of the Registrant.

The information required by this item is incorporated herein by reference to the Proxy Statement of the Company for the 2004 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 26, 2004.

Item 11. Executive Compensation.

The information required by this item is incorporated herein by reference to the Proxy Statement of the Company for the 2004 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 26, 2004.

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

The information required by this item is incorporated herein by reference to the Proxy Statement of the Company for the 2004 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 26, 2004.

Item 13. Certain Relationships and Related Transactions.

None.

Item 14. Principal Accountant Fees and Services.

The information required by this item is incorporated herein by reference to the Proxy Statement of the Company for the 2004 Annual Meeting of Stockholders. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A on or about March 26, 2004.

Filed
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at Page

Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K.

(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 each of the three years ended December 31, 2003

Consolidated Statement of Cash Flows, for each of the three years ended December 31, 2003

Consolidated Balance Sheet at December 31, 2003 and 2002

Consolidated Statement of Capitalization at December 31, 2003 and 2002

Consolidated Statement of Changes in Common Stock Equity for each of the three years ended December 31, 2003

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, 2003

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 of subsidiary companies not consolidated have been omitted since, if considered in the aggregate, they would not constitute a significant subsidiary. Separate financial statements of 50 percent or less owned persons for which the investment is accounted for by the equity method by the Registrant have been omitted since, if considered in the aggregate, they would not constitute a significant investment.

(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 Bylaws, as amended October 7, 2002. (Exhibit 99.2, Form 8-K October 7, 2002, 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)

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)

10.5 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)

10.15 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)

10.26 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)

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 10.86 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. (Form S-8 Registration Statement, Registration 333-39664)

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 10.97 Management Incentive Plan for Executive Officers dated January 1, 2002. (Exhibit A10.97, Form 10-Q, March 31, 2002, File No. 1-8222)

A 10.98 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. (Form S-8 Registration Statement, Registration 333-102008)

A - Compensation related plan, contract, or arrangement.

21 Subsidiaries of the Registrant

* 21.1 List of Subsidiaries of Registrant

23 Independent Auditors' Consent

* 23.1 Independent Auditors' Consent

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.

(b) Reports on Form 8-K:

Item 5. Dated November 25, 2003 re: Estimated increase in decommissioning costs for Connecticut Yankee Atomic Power Company of which the Company has a 2% ownership interest.

No other Current Reports on Form 8-K were filed during the fourth quarter of 2003; however

Item 5. Dated January 1, 2004 re: Completion of sale of Connecticut Valley Electric Company Inc. to Public Service Company of New Hampshire.

Item 5. Dated January 12, 2004 re: 5 percent increase in the Company's Common Stock dividend.

Items 7. & 12. On February 11, 2004 the Company filed a Current Report on Form 8-K dated February 11, 2004 under Items 7 and 12 a press release reporting the results of the Company's operations for the fourth third quarter ending December 31, 2003.

INDEPENDENT AUDITORS' REPORT
To the Board of Directors and Stockholders of
Central Vermont Public Service Corporation
Rutland, VT

We have audited the consolidated balance sheets of Central Vermont Public Service Corporation and its subsidiaries (collectively, the "Company") as of December 31, 2003 and 2002, 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, 2003 and have issued our report thereon dated February 20, 2004; such report is included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedules, referred to as Schedule II, of Central Vermont Public Service Corporation and its wholly owned subsidiaries. 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.

DELOITTE & TOUCHE LLP
Boston, MA
February 20, 2004

Schedule II

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
AND ITS WHOLLY OWNED SUBSIDIARIES

Reserves

Year ended December 31, 2003

		Additions			
	Balance at beginning of year	Charged to cost and expenses	Charged to other accounts	Deductions	Balance at end of year
Reserves deducted from assets to which they apply:					
			$121,268 (1) 495,358 (2) 426,692 (2a)	$1,948,450 (3) (4,024) (3a)	
Reserve for uncollectible accounts receivable	$1,248,663	$1,230,352	$1,043,318	$1,944,426	$1,577,907
Accumulated depreciation of miscellaneous properties:					
Rental water heater program	$3,755,167	$169,302	-	$263,356 (4)	$3,661,113
Other	675,892	75,773	-	-	751,665
	$4,431,059	$245,075		$263,356	$4,412,778
Reserves shown separately:					
Injuries and damages reserve (5)	$225,580	-	-	-	$225,580
Environmental Reserve	$7,451,789	-	-	$261,756 (6)	$7,190,633

(1) Amount collected from collection agencies
(2) Collections of accounts previously written off
(2a) Reclassed from Acct 2420 Accrued Liabilities
(3) Uncollectible accounts written off
(3a) Amount related to Connecticut Valley discontinued operations
(4) Retirement and sale of rental water heaters
(5) 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.
(6) Expenses charged against reserve

Schedule II

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
AND ITS WHOLLY OWNED SUBSIDIARIES

Reserves

Year ended December 31, 2002

	Balance at beginning of year	Additions: Charged to cost and expenses	Additions: Charged to other accounts	Deductions	Balance at end of year
Reserves deducted from assets to which they apply:					
			$102,540 (1) 316,346 (2)	$2,949,329 (3) 54,727 (3a)	
Reserve for uncollectible accounts receivable	$2,070,791	$1,763,042	$418,886	$3,004,056	$1,248,663
Accumulated depreciation of miscellaneous properties:					
Rental water heater program	$3,817,439	$181,487	-	$243,759 (4)	$3,755,167
Other	696,939	114,391	-	117,839 (6) 17,599 (7)	675,892
	$4,514,378	$295,878		$379,197	$4,431,059
Reserves shown separately:					
Injuries and damages reserve	$225,580	-	-	-	$225,580
Environmental Reserve				1,700,000 (8) 104,335 (6)	
	$9,248,313	-	$7,811 (5)	$1,804,335 (6)	$7,451,789

(1) Amount due from collection agency
(2) Collections of accounts previously written off
(3) Uncollectible accounts written off
(3a) Amount related to Connecticut Valley discontinued operations
(4) Retirements of rental water heaters
(5) Additional Reserve
(6) Expenses charged against reserve
(7) Sale of furniture
(8) Reduction of obligation

Schedule II

CENTRAL VERMONT PUBLIC SERVICE CORPORATION
AND ITS WHOLLY OWNED SUBSIDIARIES

Reserves

Year ended December 31, 2001

		Additions			
	Balance at beginning of year	Charged to cost and expenses	Charged to other accounts	Deductions	Balance at end of year
Reserves deducted from assets to which they apply:					
			$130,682 (1) 335,712 (2)		
Reserve for uncollectible accounts receivable	$1,655,190	$1,592,704	$466,394	$1,643,497 (3)	$2,070,791
Accumulated depreciation of miscellaneous properties:					
Rental water heater program	$3,845,914	$254,747	-	$283,222 (4)	$3,817,439
Other	601,165	95,774	-	-	696,939
	$4,447,079	$350,521		$283,222	$4,514,378
Reserves shown separately:					
Injuries and damages reserve	$225,580	-	-	-	$225,580
Environmental Reserve	$9,532,924		$2,305 (5)	$286,916 (6)	$9,248,313
Company Restructuring	$1,977,687	-	-	$1,977,687 (6)	$0

(1) Amount due from collection agency
(2) Collections of accounts previously written off
(3) Uncollectible accounts written off
(4) Retirements of rental water heaters
(5) Additional Reserve
(6) Expenses charged against reserve

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/ Jean H. Gibson
Jean H. Gibson
Senior Vice President, Chief Financial Officer, and Treasurer

March 10, 2004

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 10, 2004.

Signature	Title
Robert H. Young*	President and Chief Executive Officer, and Director (Principal Executive Officer)
/s/ Jean H. Gibson (Jean H. Gibson)	Senior Vice President, Chief Financial Officer, and Treasurer (Principal Accounting Officer)
Frederic H. Bertrand*	Chair of the Board of Directors
Robert L. Barnett*	Director
Rhonda L. Brooks*	Director
Janice B. Case*	Director
Robert G. Clarke*	Director
Timothy S. Cobb*	Director
Luther F. Hackett*	Director
George MacKenzie, Jr.*	Director
Mary Alice McKenzie*	Director
Janice L. Scites*	Director
Herbert H. Tate*	Director

By: /s/ Jean H. Gibson
(Jean H. Gibson)
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.