GREEN MOUNTAIN POWER CORP
Form 10-K
March 15, 2006

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2005

[ ] 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: 001-08291

GREEN MOUNTAIN POWER CORPORATION
(Exact name of registrant as specified in its charter)

VERMONT	**03-0127430**
State or other jurisdiction of Incorporation or organization	(I.R.S. Employer Identification No.)
COLCHESTER VT	**05446**
(Address of principal Executive offices)	(Zip Code)

Registrant's telephone number, including area code (802) 864-5731

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

Title of each class	Name of each exchange on which registered
COMMON STOCK, PAR VALUE $3.33-1/3 PER SHARE	NEW YORK STOCK EXCHANGE

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. oYes þNo

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. oYes þNo

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. þYes oNo

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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. þ

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

Large accelerated filero Accelerated filerþ Non-accelerated filero

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

The aggregate market value of the voting stock held by non-affiliates of the registrant as of June 30, 2005, was approximately $152,601,216 based on the closing price of $29.35 for the Common Stock on the New York Stock Exchange as reported by The Wall Street Journal.

The number of shares of Common Stock outstanding on February 22, 2006, was 5,251,038.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's Definitive Proxy Statement relating to its Annual Meeting of Stockholders to be held on May 22, 2006, to be filed with the Commission pursuant to Regulation 14A under the Securities Exchange Act of 1934, are incorporated by reference in Part III of this Form 10-K.

Green Mountain Power Corporation
Form 10-K for the fiscal year ended December 31, 2005

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PART I

There are statements in this section that contain projections or estimates and that are considered to be "forward-looking" as defined by the Securities and Exchange Commission (the "SEC"). In these statements, you may find words such as believes, expects, plans, or similar words. These statements are not guarantees of our future performance. There are risks, uncertainties and other factors that could cause actual results to be different from those projected. Some of the reasons the results may be different are discussed under Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD and A"), in the 2005 Annual Report to Shareholders ("Annual Report"), and in the accompanying Notes to Consolidated Financial Statements ("Notes"), all included herein.

ITEM 1. BUSINESS

THE COMPANY

Green Mountain Power Corporation (the "Company" or "GMP") is a public utility operating company that transmits, distributes and sells electricity and utility construction services in the State of Vermont ("State" or "Vermont") in a service territory with approximately one quarter of Vermont's population. We serve approximately 90,000 customers. The Company was incorporated under the laws of Vermont on April 7, 1893.

Our sources of retail and wholesale revenue for the year ended December 31, 2005 were as follows:

* 31.9 percent from residential customers;
* 31.1 percent from small commercial and industrial customers;
* 21.1 percent from large commercial and industrial customers;
* 11.5 percent from sales to other utilities; and
* 4.4 percent from other sources.

Nearly all of our revenue has resulted from the sale of electricity over the period 2003 - 2005.

See the Company's Annual Report and MD and A, Item 7 below, for further information about revenues.

During 2005, our energy resources for retail sales of electricity were obtained as follows:

* 43.7 percent from hydroelectric sources (33.9 percent Hydro Quebec, 6.1 percent Company-owned, and 3.7 percent independent power producers);
* 40.6 percent from a nuclear generating source (the Entergy Nuclear Vermont Yankee, LLC ("ENVY") nuclear plant described below);
* 4.1 percent from wood;
* 1.8 percent from natural gas or oil; and
* 0.1 percent from wind.

The remaining 9.7 percent was purchased on a short-term basis from generators through the wholesale market operated by ISO New England, Inc., formerly the New England Power Pool ("NEPOOL").

In 2005, we estimate that we purchased under existing contracts or generated approximately 96 percent of our energy resources to satisfy our retail and wholesale sales of electricity under long-term arrangements, including our contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract") described below. Remaining retail and wholesale sales were met through short-term market purchases and represent primarily volumetric differences between purchase commitments and our customers' retail demand. See Note J of Notes.

A major source of the Company's power supply is our entitlement to a share of the power generated by the 531 megawatt ("MW") nuclear generating plant owned and operated by Entergy Vermont Yankee Nuclear LLC ("ENVY") (the "Vermont Yankee" or "VY" plant). We have a 33.6 percent equity interest in Vermont Yankee Nuclear Power

Corporation ("VYNPC"), which has a long-term power supply contract with ENVY that entitles us to 20 percent of Vermont Yankee plant output through 2012. For further information concerning Vermont Yankee, see Power Resources - Vermont Yankee, below.

The Company owns approximately 29.2 percent of the common stock and 30.0 percent of the preferred stock of Vermont Electric Power Company, Inc. ("VELCO"). 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. For further information concerning VELCO, see VELCO below.

The Company participates in the New England regional wholesale electric power markets operated by ISO New England, Inc. ("ISO-NE") the regional bulk power transmission organization established to assure reliable and economical power supply in New England. The Federal Energy Regulatory Commission ("FERC") has granted approval to ISO-NE to become a regional transmission organization ("RTO") for New England. On February 1, 2005, ISO-NE commenced operations as the RTO, providing regional transmission service in New England, with operational control of the bulk power system and responsibility for administering wholesale markets. ISO-NE operates a market for all New England states for purchasers and sellers of electricity in the deregulated wholesale energy markets. Sellers place bids for the sale of their generation or purchased power resources and if demand is high enough the output from those resources is sold. We must purchase additional electricity to meet customer demand during periods of high usage to replace energy repurchased by Hydro Quebec under an agreement negotiated in 1997 and to replace power not delivered under our contracts and entitlements due to outages, curtailments or other events that result in reduced deliveries. Our costs to serve demand during such high usage periods, such as warmer than normal temperatures in summer months and to replace such energy repurchases by Hydro Quebec, rose substantially after the market opened to competitive bidding on May 1, 1999.

Our principal service territory is an area roughly 25 miles in width extending 90 miles across north central Vermont between Lake Champlain on the west and the Connecticut River on the east. Included in this territory are the cities and towns of Montpelier, Barre, South Burlington, Vergennes, Williston, Shelburne, and Winooski, as well as the Village of Essex Junction and a number of smaller communities. We also distribute electricity in four separate areas located in southern and southeastern Vermont that are interconnected with our principal service area through the transmission lines of VELCO and others. Included in these areas are the communities of Vernon (where the Vermont Yankee nuclear plant is located), Bellows Falls, White River Junction, Wilder, Wilmington and Dover. The Company's right to distribute electrical service in its service territory is the utility's most important asset. We supply at wholesale a portion of the power requirements of several municipalities and cooperatives in Vermont. We are obligated to meet the changing electrical requirements of these wholesale customers, in contrast to our obligation to other wholesale customers, which is limited to amounts of capacity and energy established by contract.

Major business activities in our service areas include computer assembly and components manufacturing (and other electronics manufacturing), software development, granite fabrication, service enterprises such as government, insurance, regional retail shopping, tourism (particularly fall and winter recreation), and dairy and general farming.

Operating statistics for the past five years are presented in the following table.

GREEN MOUNTAIN POWER CORPORATION
Operating Statistics

	For the years ended December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
Net system peak in MW (1)	351.9	326.7	330.2	342.0	341.2
MWH Production and purchases (2)					
Hydro	879,147	777,292	838,855	901,998	951,146
Wind, net of renewable energy credits sold	1,484	-	8,568	9,577	12,135
Nuclear	816,989	764,010	884,585	771,781	736,420
Conventional steam	93,258	89,622	100,402	85,910	33,194
Internal combustion	7,547	13,026	12,603	4,090	18,291
Combined cycle	22,328	32,224	68,488	81,362	72,653
Bilateral and system purchases(3)	647,094	804,962	2,426,091	2,347,086	2,637,055
Total production	2,467,847	2,481,136	4,339,592	4,201,804	4,460,894
Less: non-firm sales to other utilities	365,000	408,601	2,284,003	2,104,172	2,365,809
Production for firm sales	2,102,847	2,072,535	2,055,589	2,097,632	2,095,085
Less firm sales and lease transmissions	2,011,568	1,973,093	1,937,376	1,951,959	1,956,232
Losses and company use (MWH)	91,279	99,442	118,213	145,673	138,853
Losses as a % of total production	3.70%	4.01%	2.72%	3.47%	3.11%
System load factor (4)	68.2%	72.4%	71.1%	70.0%	70.1%
Net Production (% of Total)					
Hydro	35.6%	31.3%	19.3%	21.5%	21.3%
Wind	0.1%	0.0%	0.2%	0.2%	0.3%
Nuclear	33.1%	30.8%	20.4%	18.3%	16.5%
Conventional steam	3.8%	3.6%	2.3%	2.0%	0.7%
Internal combustion	0.3%	0.5%	0.3%	0.1%	0.4%
Combined cycle	0.9%	1.3%	1.6%	1.9%	1.6%
Bilateral and system purchases	26.2%	32.5%	56.0%	56.0%	59.1%
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Sales and Lease Transmissions(MWH)					
Residential - GMPC	598,606	580,710	581,047	553,294	549,151
Commercial & industrial - small	717,451	698,000	696,598	695,504	691,111
Commercial & industrial - large	686,260	684,104	651,709	689,618	710,862
Other	5,935	7,112	4,986	9,773	2,030
Total retail sales and lease transmissions	2,008,252	1,969,926	1,934,340	1,948,189	1,953,154
Sales to Municipals & Cooperatives (Rate W)	3,316	3,166	3,036	3,770	3,078
Total Requirements Sales	2,011,568	1,973,093	1,937,376	1,951,959	1,956,232
Other Sales for Resale	365,000	408,601	2,284,003	2,104,172	2,365,809
	2,376,568	2,381,694	4,221,379	4,056,131	4,322,041

Total sales and lease transmissions(MWH)										
Average Number of Electric Customers										
Residential		76,481		75,507		74,693		73,861		73,249
Commercial and industrial small		13,752		13,515		13,344		13,165		12,976
Commercial and industrial large		27		24		25		29		30
Other		60		62		65		65		65
Total		90,320		89,108		88,127		87,120		86,320
Average Revenue Per KWH (Cents)										
Residential including lease revenues		13.12		13.15		12.98		12.96		13.33
Commercial & industrial - small		10.66		10.63		10.40		10.44		10.90
Commercial & industrial - large		7.55		7.44		7.41		7.31		7.70
Total retail		10.38		10.32		10.22		10.09		10.44
Average Use and Revenue Per Residential Customer										
KWh's including lease transmissions		7,827		7,691		7,779		7,491		7,497
Revenues including lease revenues	$	1,027	$	1,012	$	1,010	$	971	$	999

(1) MW - Megawatt is one thousand kilowatts.

(2) MWH - Megawatt hour is one thousand kilowatt hours.

(3)Includes MWh generated for renewable energy credits sold

(4) Load factor is based on net system peak and firm MWH production less off-system losses.

STATE AND FEDERAL REGULATION

General. The Company is subject to the regulatory authority of the Vermont Public Service Board ("VPSB" or the "Board"), which extends to retail rates, services and facilities, securities issues and various other matters. The separate Vermont Department of Public Service ("DPS" or the "Department"), created by statute in 1981, acts as the public advocate in rate and other state regulatory proceedings and is responsible for development of energy supply plans for the State of Vermont, purchases of power as an agent for the State and other general regulatory matters. The VPSB principally conducts quasi-judicial proceedings, such as rate setting. The Department, through a Director for Public Advocacy, is entitled to participate as the public advocate in such proceedings and regularly does so. Political or social organizations that represent certain classes of customers, neighbors of our properties, or other persons or entities may petition the VPSB to be granted intervener status in such proceedings.

Our rate tariffs are uniform throughout our service area. We have entered into a number of jobs incentive agreements, providing for reduced capacity charges to large customers applicable only to new load. We have an economic development agreement with International Business Machines Corporation ("IBM") that provides for contractually established charges, rather than tariff rates, for certain loads. All such agreements must be approved by the VPSB. See Item 7. MD and A - Results of Operations - Operating Revenues and MWh Sales.

Certain components of the businesses of the Company and VELCO, including certain rates, are subject to the jurisdiction of the FERC as follows: the Company as a licensee of hydroelectric developments under Part I of the Federal Power Act, 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.

Our transmission assets and the wholesale rate on sales to two wholesale customers are regulated by the FERC. Revenues from sales to these customers were less than 1.0 percent of our operating revenues for 2005.

We provide transmission service to twelve customers within the State under rates regulated by the FERC; revenues for such services amounted to less than 1.0 percent of our operating revenues for 2005.

On July 17, 1997, the FERC approved our Open Access Transmission Tariff. On November 26, 2004, we received from FERC an exemption from the standards of conduct requirements of FERC Order 2004, governing separation of transmission operations. Our Open Access tariff could reduce the amount of capacity available to the Company from such facilities in the future. See Item 7. MD and A - Transmission Expenses.

Licensing. Pursuant to the Federal Power Act, the FERC has granted licenses for the following hydroelectric projects we own:

	Issue Date	Licensed Period
Project Site:		
Bolton	February 5,1982	February 5,1982 - February 4, 2022
Essex	March 30, 1995	March 1, 1995 - March 1, 2025
Vergennes	July 30, 1999	June 1, 1999 - May 31, 2029
Waterbury	July 20, 1954	expired August 31, 2001, renewal pending

Major project licenses provide that after an initial twenty-year period, a portion of the earnings of such project in excess of a specified rate of return is to be set aside in appropriated retained earnings in compliance with FERC Order 5, issued in 1978. The amounts appropriated are not material.

The re-licensing application for Waterbury was filed in August 1999. The Waterbury reservoir was drained in 2001 to prepare for repairs to the dam by the State and the Army Corps of Engineers. The repairs are scheduled for completion during the summer of 2006. When repairs and re-licensing proceedings are complete, we expect the project to be re-licensed for a 30-year term. We do not have any competition for the Waterbury license.

Department of Public Service Twenty-Year Electric Plan. On January 19, 2005, the Department adopted a new twenty-year electrical power-supply plan (the "Plan") for the State. The Plan includes an overview of statewide growth and development as they relate to future requirements for electrical energy; an assessment of available energy resources; and estimates of future electrical energy demand.

On August 14, 2003, we filed with the VPSB and the Department an integrated resource plan pursuant to Vermont Statute 30 V.S.A. § 218c. That filing is pending before the VPSB.

RECENT RATE DEVELOPMENTS

The Company expects to file a retail rate case requesting a rate increase estimated at between ten and fifteen percent in 2006, effective for January 1, 2007.

The VPSB issued an order on December 22, 2003 approving the Company's 2003 Rate Plan (the "2003 Rate Plan"), jointly proposed by the Company and the Department. Principal terms of the 2003 Rate Plan include:

* Allows the Company to raise rates 1.9 percent, effective January 1, 2005; and 0.9 percent effective January 1, 2006, if the increases are supported by cost of service schedules submitted 60 days prior to the effective dates. The Company filed cost of service schedules pursuant to the plan in November 2004 and November 2005, respectively, and received approval from the VPSB to implement the plan's 2005 1.9 percent rate increase, effective January 1, 2005, and the plan’s 2006 0.9 percent rate increase, effective January 1, 2006.

* Allows the Company the opportunity to file for rate increases during the period from January 1, 2003 to December 31, 2006 if the Company experiences extraordinary events, such as repair costs due to an ice storm or other natural disaster.

    * Reduces the Company's allowed return on equity from 11.25 percent to 10.5 percent for the period beginning January 1, 2003 to January 1, 2007.

* Provides for recovery of various regulatory assets, including the remediation of the Pine Street environmental superfund site in Burlington, VT.

For further discussion of the Company's 2003 Rate Plan, see Item 7a. Quantitative and Qualitative Disclosures About Market Risk - Rates.

SINGLE CUSTOMER DEPENDENCE

The Company had one major retail customer, IBM, that accounted for 15.3 percent, 16.2 percent and 16.6 percent of the Company’s retail operating revenues in 2005, 2004 and 2003, respectively. No other retail customer accounted for more than 1.0 percent of our revenue during the past three years.

IBM has reduced its Vermont workforce by approximately 2,500 since 2001, to a level of approximately 6,000 employees. We currently estimate, based on a number of projected variables, that a hypothetical shutdown of the IBM facility, inclusive of the tertiary effects on commercial and residential customers, would not necessitate retail rate increases because the Company could sell contracted power supply resources into the wholesale market at prices in excess of those charged to IBM. This estimate would change materially as a result of any significant reductions in wholesale energy prices or increases in retail rates paid by IBM. See Item 7a. Quantitative and Qualitative Disclosures About Market Risk - Customer Concentration Risk, and Note A of Notes.

COMPETITION AND RESTRUCTURING

Competition currently takes several forms. At the wholesale level, New England has implemented its version of FERC's "standard market design ("SMD"), which is a detailed competitive market framework that has resulted in bid-based competition of power suppliers rather than prices set under cost of service regulation. At the retail level, customers have long had energy options such as propane, natural gas or oil for heating, cooling and water heating, and self-generation. Another competitive risk is the potential for customers to form municipally owned utilities in the Company's service territory.

In 1987, the Vermont General Assembly enacted legislation that authorized the Department to sell electricity on a significantly expanded basis. Under the 1987 law, the Department can sell electricity purchased from any source at retail to all customer classes throughout the State, but only if the VPSB and other State officials determine that the public good will be served by such sales. Since 1987, the Department has made limited retail sales of electricity.

In certain states across the country, including other New England states, legislation has been enacted to allow retail customers to choose their electricity suppliers, with incumbent utilities required to deliver that electricity over their transmission and distribution systems. Increased competitive pressure in the electric utility industry could potentially restrict the Company’s ability to charge energy prices sufficient to recover embedded costs, such as the cost of purchased power obligations or of generation facilities owned by the Company. There are currently no regulatory proceedings, court actions or pending legislative proposals to adopt electric industry restructuring in Vermont.

CONSTRUCTION AND CAPITAL REQUIREMENTS

Our capital expenditures for 2003 through 2005 and projected for 2006 are set forth in Item 7. MD and A - Liquidity and Capital Resources-Construction. Construction projections are subject to continuing review and may be revised from time-to-time in accordance with changes in the Company's financial condition, load forecasts, the availability and cost of labor and materials, licensing and other regulatory requirements, changing environmental standards and other relevant factors. See Item 7. MD and A - Liquidity and Capital Resources.

POWER RESOURCES

We generated, purchased or transmitted 2,011,568 MWh of energy for retail and requirements wholesale customers for the twelve months ended December 31, 2005. The corresponding maximum one-hour integrated demand during that period was 351.9 MW on July 19, 2005. This compares to the previous all-time peak of 342.0 MW on August 15, 2002. The following table shows the net generated and purchased energy, the source of such energy for the twelve-month period and the capacity in the month of the period system peak. See Note J of Notes.

Net Electricity Generated and Purchased and Capacity at Peak

	Generated and Purchased for the year ended December 31, 2005		Capacity At time of of annual peak	
	MWH	percent	KW	percent
Wholly-owned plants:				
Hydro	121,760	6.1%	23,370	6.3%
Diesel and Gas Turbine	7,547	0.4%	58,550	15.8%
Wind*	1,484	0.1%	960	0.3%
Jointly-owned plants:				
Wyman #4	7,248	0.4%	6,470	1.7%
Stony Brook I	15,328	0.8%	30,936	8.3%
McNeil	26,000	1.3%	5,770	1.6%

Long Term Purchases:				
Vermont Yankee/ENVY	816,989	40.6%	97,451	26.3%
Hydro Quebec	680,984	33.9%	107,391	29.0%
Stony Brook I	7,000	0.3%	14,124	3.8%
Other:				
Independent Power Producers	131,774	6.6%	25,610	6.9%
-				-
ISO-NE and Short-term purchases	195,454	9.6%	-	-
Net Own Load	2,011,568	100.0%	370,632	100.0%

*Net of renewable energy certificates sold representing 10,000MWh

Vermont Yankee

On July 31, 2002, VYNPC completed the sale of its nuclear power plant to ENVY. In addition to the sale of the generating plant, the transaction calls for ENVY, through its power contract with VYNPC, to provide 20 percent of the plant output to the Company through 2012, which represents approximately 35 percent of our projected energy requirements.

Prices under the Power Purchase Agreement between VYNPC and ENVY (the "PPA") range from $39 to $45 per megawatt-hour for the period beginning January 2003. The PPA calls for a downward adjustment in the price if market prices for electricity fall by defined amounts beginning no later than November 2005. If market prices rise, however, contract prices are not adjusted upward. The Company remains responsible for procuring replacement energy at market prices during periods of scheduled or unscheduled outages at the Vermont Yankee plant.

Our ownership share of VYNPC increased from approximately 19.0 percent to approximately 33.6 percent in 2003, due to VYNPC's purchase of certain minority shareholders' interests. VYNPC's primary role consists of administering its power supply contract with ENVY and its contracts with VYNPC's present sponsors. Our entitlement to energy produced by the Vermont Yankee nuclear plant has remained at 20 percent of plant production.

During periods when Vermont Yankee power is unavailable, the costs of replacement power occasionally exceed those costs that we would have incurred for power purchased pursuant to our power supply agreement with VYNPC. Replacement power is available to us from the wholesale market and through contractual arrangements with other utilities. Replacement power costs can adversely affect cash flow, and, unless deferred and/or recovered in rates, such costs could adversely affect reported earnings. In the case of unscheduled outages of significant duration resulting in substantial unanticipated costs for replacement power, the VPSB generally has authorized deferral and recovery of such costs.

Vermont Yankee's current operating license expires March 2012. Since the Company no longer owns an interest in the Vermont Yankee nuclear plant, we no longer bear the operating costs and risks associated with running and decommissioning the plant.

During the year ended December 31, 2005, we used 816,989 MWh of Vermont Yankee energy (supplied by ENVY) representing 40.6 percent of the net electricity generated and purchased ("net power supply") by the Company.

See Item 7a. Quantitative and Qualitative Disclosures About Market Risk - Other Power Supply Risks, and Notes B and J of Notes for additional information.

Hydro Quebec

Highgate Interconnection. On September 23, 1985, the Highgate transmission facilities, which were constructed to import energy from Hydro Quebec in Canada, began commercial operation. The transmission facilities at Highgate include a 225-MW AC-to-DC-to-AC converter terminal and seven miles of 345-kV transmission line. VELCO built and operates the converter facilities, which we own jointly with a number of other Vermont utilities. Commencing with implementation of New England's RTO, the Highgate facilities are now controlled and operated by ISO-NE. We do not expect ISO-NE’s control or operation of these facilities to affect the Company’s deliveries of power from Hydro Quebec under our current power contract commitments.

NEPOOL/Hydro Quebec Interconnection. VELCO and certain other NEPOOL members have entered into agreements with Hydro Quebec, which provided for the construction in two phases of a direct interconnection between the electric systems in New England and the electric system of Hydro Quebec in Canada. The Vermont participants in this project, which has a capacity of 2,000 MW, will derive approximately 9.0 percent of the total power-supply benefits associated with the NEPOOL/Hydro Quebec interconnection. The Company, in turn, receives approximately one-third of the Vermont share of those benefits. The benefits of the interconnection include:

* access to surplus hydroelectric energy from Hydro Quebec; and
* a provision for emergency transfers and mutual backup to improve reliability for both the Hydro Quebec system and the New England systems.

Phase I. The first phase ("Phase I") of the NEPOOL/Hydro Quebec Interconnection consists of transmission facilities having a capacity of 690 MW that originate at the Des Cantons Substation on the Hydro Quebec system near Sherbrooke, Canada and traverse a portion of eastern Vermont and extend to a converter terminal located in Comerford, New Hampshire. VETCO was formed to construct and operate the portion of Phase I within the United States. Under the Phase I contracts, each New England participant, including the Company, is required to pay monthly its proportionate share of VETCO's total cost of service, including its capital costs. Each participant also pays a proportionate share of the total costs of service associated with those portions of the transmission facilities constructed in New Hampshire by a subsidiary of National Grid, successor to New England Electric System.

Phase II. Phase II provides 2,000 MW of capacity for transmission of Hydro Quebec power to Sandy Pond, Massachusetts. The participants in this project, including the Company, have contracted to pay monthly their proportionate share of the total cost of constructing, owning and operating the Phase II facilities, including capital costs. As a supporting participant, the Company must make support payments under 30-year agreements. These support agreements meet the capital lease accounting requirements under SFAS 13. At December 31, 2005, the present value of the Company's obligation was approximately $3.9 million. The Company's projected future minimum payments under the Phase II support agreements are approximately $385,000 for each of the years 2006-2010 and an aggregate of $1.9 million for the years 2011-2015.

The Phase II portion of the project is owned by New England Hydro-Transmission Electric Company, Inc. and New England Hydro-Transmission Corporation, subsidiaries of National Grid, successor to New England Electric System, in which certain of the Phase II participating utilities, including the Company, own equity interests. The Company owns approximately 3.2 percent of the equity of the corporations owning the Phase II facilities. See Notes B and I of Notes.

Hydro Quebec Power Supply Contracts. The bulk of our purchases from Hydro Quebec are pursuant to two schedules, B and C3, of a Firm Contract dated December 1987 (the "VJO Contract"). Under these two schedules, we purchase 114.2 MW from Hydro Quebec. In November 1996, we entered into an agreement (the "9701 agreement") with Hydro Quebec under which Hydro Quebec paid $8.0 million to the Company in exchange for certain power purchase options. See Item 7a. Quantitative and Qualitative Disclosures About Market Risk - Power Contract Commitments, and Note J of Notes.

During 2005, we used 402,910 MWh under Schedule B, and 278,074 MWh under Schedule C3 of the VJO Contract, representing 33.9 percent of our net power supply.

Morgan Stanley Contract - On February 11, 1999, the Company entered into a contract with Morgan Stanley Capital Group, Inc. ("Morgan Stanley"). In August 2002, the Morgan Stanley Contract was modified and extended to December 31, 2006. The contract provides us a means of managing price risks associated with changing fossil fuel prices. For additional information on the Morgan Stanley Contract, see 7a. Quantitative and Qualitative Disclosures About Market Risk - Power Contract Commitments and Note J of Notes.

ISO-NE and Short-term Opportunity Purchases and Sales - We have arrangements with numerous utilities and power marketers actively trading power in New England and New York under which we purchase or sell power on short notice and generally for brief periods of time when required to balance electricity supply with demand. Opportunity purchases are also arranged when it is possible to purchase power for less than it would cost us to generate the power with our own sources. Purchases may also help us save on replacement power costs during an outage of one of our base load sources. Opportunity sale prices are generally set to recover all of the forecasted fuel or production costs and to recover some, if not all, associated capacity costs. During 2005, the Company purchased 195,454 MWh representing 9.6 percent of the Company's net power supply.

Stony Brook I. The Massachusetts Municipal Wholesale Electric Company ("MMWEC") is principal owner and operator of Stony Brook, a 352.0-MW combined-cycle intermediate generating station located in Ludlow, Massachusetts, which commenced commercial operation in November 1981. In October 1997, we entered into a Joint Ownership Agreement with MMWEC, whereby we acquired an 8.8 percent ownership share of the plant, entitling us to 31.0 MW of capacity. In addition to this entitlement, we have contracted for 14.2 MW of capacity for the life of the Stony Brook I plant, for which we will pay a proportionate share of MMWEC's share of the plant's fixed costs and variable operating expenses. The three units that comprise Stony Brook I are all capable of burning oil. Two of the units are also capable of burning natural gas. The natural gas system at the plant was modified in 1985 to allow two units to operate simultaneously on natural gas.

During 2005, we used 22,328 MWh from this plant representing 1.1 percent of our net power supply. See Notes H and J of Notes.

Wyman Unit #4. The W. F. Wyman Unit #4, which is located in Yarmouth, Maine, is an oil-fired steam plant with a capacity of 620 MW. Florida Power & Light is the principal owner and operator of the plant. We have a joint-ownership share of 1.1 percent (7.1 MW) in the Wyman #4 Unit, which began commercial operation in December 1978.

During 2005, we used 7,248 MWh from this unit representing 0.4 percent of our net power supply. See Note H of Notes.

McNeil Station. The J.C. McNeil station (the "McNeil Plant"), which is located in Burlington, Vermont, is a wood chip and gas-fired steam plant with a capacity of 53.0 MW. We have an 11.0 percent or 5.8 MW interest in the McNeil Plant, which began operation in June 1984. In 1989, the plant added the capability to burn natural gas on an as-available/interruptible service basis.

During 2005, we used 26,000 MWh from this unit representing 1.3 percent of our net power supply. See Note H of Notes. The Burlington Electric Department is the principal owner and operator of the McNeil plant.

Independent Power Producers. The VPSB has adopted rules that implement for Vermont the purchase requirements established by federal law in the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Under the rules, qualifying facilities have the option to sell their output to a central state-appointed purchasing agent under a variety of long-term and short-term, firm and non-firm pricing schedules. Each of these schedules is based upon the projected

Vermont composite system's power costs that would be required but for the purchases from independent producers. The State's purchasing agent assigns the energy so purchased, and the costs of purchase, to each Vermont retail electric utility based upon its pro rata share of total Vermont retail energy sales. Utilities may also contract directly with producers. The rules provide that all reasonable costs incurred by a utility under the rules will be included in the utilities' revenue requirements for ratemaking purposes.

Currently, the State purchasing agent, Vermont Electric Power Producers, Inc. ("VEPPI"), is authorized to seek 150 MW of power from qualifying facilities under PURPA, of which our average pro rata share in 2005 was approximately 34.3 percent or 51.5 MW.

The rated capacity of the qualifying facilities currently selling power to VEPPI is approximately 74.5 MW. These facilities were all online by the spring of 1993, and no other projects are currently under development.

In 2005, through our direct contracts and VEPPI, we purchased 131,774 MWh of qualifying facilities production representing 6.6 percent of our net power supply.

Company Hydroelectric Power. We wholly-own and operate eight hydroelectric generating facilities located on river systems within our service area, the largest of which has a generating output of 7.8 MW.

In 2005, Company owned hydroelectric plants produced 121,760 MWh, representing 6.1 percent of our net power supply. See State and Federal Regulation - Licensing.

VELCO. The Company and fifteen other Vermont electric distribution utilities own VELCO. Since commencing operation in 1958, VELCO has transmitted power for its owners in Vermont, including power from the New York Power Authority and other power contracted for by Vermont utilities. VELCO is a member of NEPOOL and represents Vermont electric utilities in some pool matters. See Note B of Notes.

Fuel. See the discussion about energy resources under the description of the Company in Item 1.

We do not maintain long-term contracts for the supply of oil for our wholly owned oil-fired peak generating stations (80 MW). We did not experience difficulty in obtaining oil for our own units during 2005. None of the utilities from which we expect to purchase oil- or gas-fired capacity in 2005 has advised us of grounds for doubt about maintenance of secure sources of oil and gas during the year.

Wood for the McNeil plant is furnished to the Burlington Electric Department from a variety of sources under short-term contracts ranging from several weeks' to six months' duration.

The Stony Brook combined-cycle generating station is capable of burning either natural gas or oil in two of its turbines. Natural gas is supplied to the plant subject to its availability. During periods of extremely cold weather, the supplier reserves the right to discontinue deliveries to the plant in order to satisfy the demand of its residential customers. We assume, for planning and budgeting purposes, that the plant will be supplied with gas during the months of April through November, and that it will run solely on oil during the months of December through March.

Searsburg Wind Project. The Company was selected by the Department of Energy ("DOE") and the Electric Power Research Institute ("EPRI") to build a commercial scale wind-powered facility in Searsburg, Vermont. The DOE and EPRI provided partial funding for the wind project of approximately $3.9 million. The net expenditures to the Company of the project, located in the southern Vermont town of Searsburg, was $7.8 million. The eleven wind turbines have a rating of 6 MW and were commissioned July 1, 1997. In 2005, the project produced 11,484 MWh, representing 0.1 percent of the Company's net power supply, net of renewable energy certificates sold.

SEGMENT INFORMATION

Financial information about the Company's primary industry segment, the electric utility, is presented in Item 6, Selected Financial Data, and in the Annual Report and Notes included herein.

The Company has sold or disposed of substantially all of the operations and assets of Northern Water Resources, Inc. ("NWR"), formerly known as Mountain Energy, Inc., classified as discontinued operations in 1999.

SEASONAL NATURE OF BUSINESS

Winter recreational activities, longer hours of darkness and heating loads from cold weather historically caused our average peak electric sales to occur in December, January or February. Summer air conditioning loads have increased in recent years as a result of steady economic growth in our service territory. As a result, our heaviest load, 351.9 MW, occurred on July 19, 2005.

EMPLOYEES

As of December 31, 2005, the Company had 195 employees, exclusive of temporary employees. The Company considers its relations with employees to be excellent. The current labor contract expires December 31, 2007.

ENERGY EFFICIENCY

In 2005, GMP did not offer its own energy efficiency programs. Energy efficiency services were provided to GMP's customers by a statewide Energy Efficiency Utility ("EEU") known as "Efficiency Vermont," created by the VPSB in 1999. The EEU is funded by a separate energy efficiency charge that appears as a line item on each customer bill. A charge per KW and per KWH is applied. The purpose of these charges is to apply equal efficiency charges across Vermont to customers with similar usage, regardless of their local utility rates. The charge represents two to three percent of each customer's total electric bill. The funds we collect are remitted to a fiscal agent representing the State of Vermont.

RATE DESIGN

The Company seeks to design rates to encourage efficient electrical use. Since 1976, we have offered optional time-of-use rates for residential and commercial customers. In March 2004, the Company filed with the VPSB a new fully-allocated cost of service study and rate re-design, which re-allocates the Company's revenue requirement among all customer classes on the basis of current costs. The Company's new rate design was approved by the VPSB in 2005. We do not expect the new rate design to adversely affect operating results. The Company’s rate design objectives are to provide a stable pricing structure and to accurately reflect the cost of providing electric services. This rate structure helps to achieve these goals. Since inefficient use of electricity increases its cost, customers who are charged prices that reflect the cost of providing electrical service have incentives to follow the most efficient usage patterns.

CURTAILABLE SERVICE

At December 31, 2005, we had 24 customers receiving service under a power tariff. The curtailable tariff allows customers to receive a portion of their electricity at favorable rates except during times when energy prices or demand are high. The customer’s demand during these periods is not considered in calculating the monthly billing. This program enables the Company and the customers to benefit from load control. We shift load from our high cost peak periods and the customer uses inexpensive power at a time when its use provides maximum value. These programs are available by tariff for qualifying customers.

ENVIRONMENTAL MATTERS

We had been notified by the Environmental Protection Agency ("EPA") that we were one of several potentially responsible parties for clean up at the Pine Street Barge Canal site in Burlington, Vermont. In September 1999, we negotiated a final settlement with the United States, the State of Vermont, and other parties over terms of a Consent Decree that covers claims addressed in earlier negotiations and implementation of the selected remedy. In October 1999, the federal district court approved the Consent Decree that addresses claims by the EPA for past Pine Street Barge Canal site costs, natural resource damage claims and claims for past and future oversight costs. The Consent Decree also provides for the design and implementation of response actions at the site. For information regarding the

Pine Street Barge Canal site and other environmental matters, see Item 7. MD and A- Environmental Matters, and Note H of Notes.

UNREGULATED BUSINESSES
During 1999, the Company discontinued operations of Northern Water Resources, Inc. ("NWR"), a subsidiary of the Company that invested in wastewater, energy efficiency and generation businesses. NWR's remaining assets include an interest in a wind generation facility in California, a non-performing note from a hydroelectric facility in New Hampshire, and a wastewater business in the process of completing dissolution. For information regarding our unregulated businesses, see Note A of Notes.

EXECUTIVE OFFICERS
The names, ages, and positions of our Executive Officers, in alphabetical order, as of March 14, 2006 are:
Christopher L. Dutton 57
President and Chief Executive Officer of the Company and Chairman of the Executive Committee of the Company since August 1997. Vice President, Finance and Administration, Chief Financial Officer and Treasurer from 1995 to August 1997. Vice President and General Counsel from 1993 to January 1995. Vice President, General Counsel and Corporate Secretary from 1989 to 1993.

Robert J. Griffin 49
Chief Financial Officer and Principal Accounting Officer since December 2003. Vice President since July 2003. Treasurer since February 2002. Controller from October 1996 to December 2003. Manager of General Accounting from 1990 to 1996.

Walter S. Oakes 59
Vice President-Field Operations since August 1999. Assistant Vice President-Customer Operations from June 1994 to August 1999. Assistant Vice President, Human Resources from August 1993 to June 1994. Assistant Vice President-Corporate Services from 1988 to 1993.

Mary G. Powell 45
Senior Vice President-Chief Operating Officer since April 2001. Senior Vice President-Customer and Organizational Development from December 1999 to April 2001. Vice President-Administration from February 1999 through December 1999. Vice President, Human Resources and Organizational Development from March 1998 to February 1999. Prior to joining the Company, Ms. Powell was President of HRworks, Inc., a human resources management firm, from January 1997 to March 1998. Prior to HRworks, Inc. Ms. Powell was Senior Vice President of Community Banking for Key Bank of Vermont, from 1992 to 1997.

Donald J. Rendall 50
Vice President, General Counsel and Corporate Secretary since July 2002, March 2002, and December 2002, respectively. Prior to joining the Company, Mr. Rendall was a principal in the Burlington, Vermont law firm of Sheehey, Furlong, Rendall & Behm, P.C. from 1988 to February 2002.

Robert E. Rogan 46
Vice President of Public Affairs since October 2005. Prior to joining the Company, Mr. Rogan was Deputy Campaign Manager for the Dean for America presidential campaign from 2003 - 2005, Vice President of Public Affairs for Central Vermont Public Service Corporation from 1998 to 2003, and Deputy Chief of Staff to Vermont Governor Howard Dean from 1994 to 1998.

Stephen C. Terry 64
Senior Vice President-Corporate and Legal Relations since August 1999. Senior Vice President, Corporate Development from August 1997 to August 1999. Vice President and General Manager, Retail Energy Services from 1995 to August 1997. Vice President-External Affairs from 1991 to January 1995. Mr. Terry retired from the

Company of January 6, 2006.

The Board of Directors of the Company and its wholly-owned subsidiaries, as appropriate, elects officers for one-year terms to serve at the pleasure of such boards of directors.

Additional information regarding compensation, beneficial ownership of the Company's stock, members of the board of directors, and other information is presented in the Company's Proxy Statement to Shareholders dated April 12, 2005, and is hereby incorporated by reference.

AVAILABLE INFORMATION

Our Internet website address is: www.greenmountainpower.biz. We make available free of charge through the website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after such documents are electronically filed with, or furnished to, the SEC. We also make available on the website the Company's Corporate Governance Guidelines, Code of Ethics and Conduct, Bylaws, and the Charters of the Audit, Compensation and Governance Committees of the Company. The information on our website is not, and shall not be deemed to be, a part of this report or incorporated into any other filings we make with the SEC.

ITEM 1A. RISK FACTORS

The risk factors included in Item 7A - Quantitative and Qualitative Disclosures About Market Risk - are incorporated by reference herein.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

GENERATING FACILITIES

Our Vermont properties are located in five areas and are interconnected by transmission lines of VELCO and New England Power Company. We wholly own and operate eight hydroelectric generating stations with a total nameplate rating of 36.1 MW. We also own two gas-turbine generating stations with an aggregate nameplate rating of 63.6 MW. We have two diesel generating stations with an aggregate nameplate rating of 6.0 MW. We also have a wind generating facility with a nameplate rating of 6.1 MW.

We also own:

* 33.6 percent of the outstanding common stock of Vermont Yankee Nuclear Power Corporation and, through its contract with ENVY, we are entitled to 20.0 percent (106.2 MW of a total 531 MW) of the capacity of the Vermont Yankee nuclear generating plant,
* 1.1 percent (7.0 MW of a total 620 MW) joint-ownership share of the Wyman #4 plant located in Maine,
* 8.8 percent (30.2 MW of a total 352 MW) joint-ownership share of the Stony Brook I intermediate units located in Massachusetts, and
* 11.0 percent (5.5 MW of a total 53 MW) joint-ownership share of the J.C. McNeil wood-fired steam plant located in Burlington, Vermont.

See Item 1. Business - Power Resources for plant details and the table hereinafter set forth for generating facilities presently available.

TRANSMISSION AND DISTRIBUTION

The Company had, at December 31, 2005, approximately 2 miles of 115 kV transmission lines, 10 miles of 69 kV transmission lines, 5 miles of 44 kV transmission lines, 196 miles of 34.5 kV transmission lines, and 2 miles of 13.8 kV transmission lines. Our distribution system included approximately 2,475 miles of overhead lines of 2.4 to 34.5 kV and 438 miles of underground cable of 2.4 to 34.5 kV. At such date, we owned approximately 115,000 kV of substation transformer capacity in transmission substations and 600,000 kV of substation transformer capacity in distribution substations and approximately 931,000 kV of transformers for step-down from distribution to customer use.

The Company owns 34.8 percent of the Highgate transmission inter-tie, a 225-MW converter and transmission line used to transmit power from Hydro Quebec. The Company also owns 59.4 percent of the metallic neutral return, a neutral conductor for the NEPOOL/Hydro Quebec interconnection.

We also own 29.2 percent of the common stock and 30 percent of the preferred stock of VELCO, which operates a high-voltage transmission system interconnecting electric utilities in the State of Vermont.

VELCO's properties consist of approximately 573 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 National Grid; 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.

VELCO's wholly-owned subsidiary, 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.

PROPERTY OWNERSHIP

Our wholly-owned plants are located on lands that we own in fee. Water power and floodage rights are controlled through ownership of the necessary land in fee or under easements.

Transmission and distribution facilities that are not located in or over public highways are, with minor exceptions, located either on land owned in fee or pursuant to easements which, in nearly all cases, 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 by state or municipal authorities.

INDENTURE OF FIRST MORTGAGE

The Company’s interests in substantially all of its properties and franchises are subject to the lien of the mortgage securing its First Mortgage Bonds. See Note E, Long-Term Debt, for more information concerning our First Mortgage Bonds.

GENERATING FACILITIES OWNED

The following table gives information with respect to generating facilities presently available in which the Company has an ownership interest. See also Item 1. Business - Power Resources.

	Location	Name	Energy Source	Name Plate Rating MW
Wholly Owned				
Hydro	Middlesex, VT	Middlesex #2	Hydro	3.6
	Marshfield, VT	Marshfield #6	Hydro	5.0
	Vergennes, VT	Vergennes #9	Hydro	2.4
	W. Danville, VT	W. Danville #15	Hydro	1.0

	Colchester, VT	Gorge #18	Hydro	3.0
	Essex Jct., VT	Essex #19	Hydro	7.2
	Waterbury, VT	Waterbury #22 (1)	Hydro	5.5
	Bolton, VT	DeForge #1	Hydro	8.4
Diesel	Vergennes, VT	Vergennes #9	Oil	4.0
	Essex Jct., VT	Essex #19	Oil	2.0
Gas Turbine	Berlin, VT	Berlin #5	Oil	46.6
	Colchester, VT	Gorge #16	Oil	17.0
Wind	Searsburg, VT	Searsburg	Wind	6.1
Jointly Owned				
Steam	Yarmouth, ME	Wyman #4	Oil	7.0
	Burlington, VT	McNeil (2)	Wood/Gas	5.5
Combined	Ludlow, MA	Stony Brook #1	Oil/Gas	30.2
Total Winter Capability				154.5

(1) Reservoir has been drained, dam awaiting repairs by the State of Vermont.
(2) The Company's entitlement in McNeil is 5.5 MW. However, we receive up to 6.6 MW as a result of other owners' losses.

CORPORATE HEADQUARTERS
Our headquarters and main service center are located in Colchester Vermont, one of the most rapidly growing areas of our service territory.

ITEM 3. LEGAL PROCEEDINGS
The Company is not involved in any material litigation at the present time. See the discussion under Item 7. MD and A - Other Risks, Environmental Matters, Rates, and Note H of Notes.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS
None.

PART II
ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES
Outstanding shares of our Common Stock are listed and traded on the New York Stock Exchange under the symbol GMP. The following tabulation shows the high and low sales prices for the Common Stock on the New York Stock Exchange during 2005 and 2004:

	HIGH	LOW
2005		
First Quarter	$ 30.88	$ 27.87
Second Quarter	30.00	28.85
Third Quarter	33.03	28.75
Fourth Quarter	33.08	26.62
2004		
First Quarter	$ 26.29	$ 22.60
Second Quarter	26.10	24.40
Third Quarter	26.82	25.08
Fourth Quarter	29.15	24.80

The number of common stockholders of record as of February 22, 2006 was approximately 4,565, $3.33333 par value.

Quarterly cash dividends were paid as follows during the past two years:

	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
2004	$0.22	$0.22	$0.22	$0.22
2005	$0.25	$0.25	$0.25	$0.25

Dividend Policy. The Company increased its common dividend in February 2006 from an annual rate of $1.00 per share to $1.12 per share. The Company increased its dividend in February 2005 from an annual rate of $0.88 per share to $1.00 per share. The Company's dividend payout ratio remains comparatively low, at approximately 48 percent of 2005 earnings from continuing operations. We expect to grow our dividend payout ratio to the middle of a payout range of between 50 and 70 percent over the next five years, in line with other electric utilities having similar risk profiles, so long as financial and operating results permit.

ITEM 6. SELECTED FINANCIAL DATA

Results of Operations for the years ended December 31,

In thousands, except per share data	2005	2004	2003	2002	2001
Operating Revenues	$ 245,860	$ 230,574	$ 280,470	$ 274,608	$ 283,464
Operating Expenses	229,779	215,096	265,164	259,528	267,005
Operating Income	16,081	15,478	15,306	15,080	16,459
Other Income					
AFUDC - equity	29	449	387	233	210
Other	1,696	1,638	1,692	2,252	2,163
Total other income	1,725	2,087	2,079	2,485	2,373
Interest Charges					
AFUDC - borrowed	(18)	(285)	(267)	(103)	(188)
Other	6,778	6,791	7,324	6,273	7,227
Total interest charges	6,760	6,506	7,057	6,170	7,039
Net Income from continuing operations before preferred dividends	11,046	11,059	10,328	11,395	11,793
Net Income (Loss) from discontinued operations, including provisions for loss on disposal	134	525	79	99	(182)
Dividends on Preferred Stock	-	-	3	96	933
Net Income Applicable to Common Stock	$ 11,180	$ 11,584	$ 10,404	$ 11,398	$ 10,678
Common Stock Data					
Basic earnings per share-continuing operations	$ 2.12	$ 2.18	$ 2.08	$ 2.02	$ 1.93
Basic earnings per share-discontinued operations	$ 0.03	$ 0.10	$ 0.01	$ 0.02	$ (0.03)
Basic earnings per share	$ 2.15	$ 2.28	$ 2.09	$ 2.04	$ 1.90
Diluted earnings per share from continuing operations	$ 2.09	$ 2.10	$ 2.01	$ 1.96	$ 1.88
Diluted earnings (loss) per share from discontinued operations	$ 0.03	$ 0.10	$ 0.01	$ 0.02	$ (0.03)
Diluted earnings per share	$ 2.12	$ 2.20	$ 2.02	$ 1.98	$ 1.85
Cash dividends declared per share	$ 1.00	$ 0.88	$ 0.76	$ 0.60	$ 0.55
Weighted average shares outstanding-basic	5,195	5,083	4,980	5,592	5,630
Weighted average equivalent shares outstanding-diluted	5,284	5,254	5,140	5,756	5,789

Financial Condition as of December 31

In thousands	2005	2004	2003	2002	2001
Assets					
Utility Plant, Net	$ 236,911	$ 232,712	$ 228,862	$ 223,476	$ 196,858

Other Investments	20,663	18,959	13,706	21,552	20,945
Current Assets	64,312	44,809	31,688	31,432	36,183
Deferred Charges	51,729	55,120	55,590	60,390	72,468
Non-Utility Assets	653	755	1,105	995	1,075
Total Assets	$ 374,268	$ 352,355	$ 330,951	$ 337,845	$ 327,529
Capitalization and Liabilities					
Common Stock Equity	$ 117,374	$ 109,581	$ 99,915	$ 91,722	$ 101,277
Redeemable Cumulative Preferred Stock	-	-	-	55	12,560
Long-Term Debt, Less Current Maturities	79,000	93,000	93,000	93,000	74,400
Capital Lease Obligation	3,944	4,493	4,963	5,287	5,959
Current Liabilities	63,156	33,815	22,715	38,491	38,841
Deferred Credits and Other	108,420	109,295	108,281	107,349	92,791
Non-Utility Liabilities	2,374	2,171	2,077	1,941	1,701
Total Capitalization and Liabilities	$ 374,268	$ 352,355	$ 330,951	$ 337,845	$ 327,529

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS ("MD and A")

Executive Overview - Green Mountain Power Corporation (the "Company") generates most of its earnings from retail electricity sales. Our retail electricity sales have grown at an average annual rate of between one and two percent, about average for most electric utility companies in New England. In periods of very high energy prices, wholesale revenues and expenses arising primarily from sales and purchases to accommodate volumetric difference between energy supplies and customer demand can affect earnings to a significant degree. The Company is regulated and cannot adjust prices of retail electricity sales without regulatory approval from the Vermont Public Service Board ("VPSB").

The Company increased its common stock dividend in February 2006 from an annual rate of $1.00 per share to $1.12 per share. The Company's dividend payout ratio during 2005 was comparatively low, at approximately 48 percent of 2005 earnings from continuing operations. We expect to grow our dividend payout ratio to the middle of a payout range of between 50 and 70 percent over the next five years, in line with other electric utilities having similar risk profiles, so long as financial and operating results permit.

Fair regulatory treatment is fundamental to maintaining the Company's financial stability. Rates must be set at levels to recover costs, including a market rate of return to equity and debt holders in order to attract capital. The Company's allowed rate of return on its regulated operations is currently capped at 10.5 percent, reduced by amounts normally excluded for purposes of setting rates and is determined by the VPSB. Nearly all of the Company's continuing operations are treated for ratemaking purposes as regulated operations. The Company's 2005 return on equity was 9.85 percent reflecting the exclusions mentioned above. These exclusions also make it unlikely that the Company's operating results will achieve its allowed rate of return while its earnings are subject to the earnings cap. The Company is currently operating under a three-year rate plan approved by the VPSB in December 2003 (the "2003 Rate Plan"). The 2003 Rate Plan covers the period 2004 - 2006 and has provided the Company with a stable, predictable rate path through 2006, a plan for full recovery of the Company's principal regulatory assets, and an improved opportunity to earn a fair rate of return. The 2003 Rate Plan is described in more detail below under "Rates."

Power supply expenses were equivalent to approximately 65 percent of total operating expenses in 2005. Therefore, any significant increase in the cost of our power supply resources would likely require the Company to seek a rate increase. The Company expects to file a retail rate case requesting a rate increase estimated at between ten and fifteen percent in 2006, effective for January 1, 2007, partially as a result of the need to replace an expiring power supply contract. We have entered into long-term power supply contracts for most of our energy needs. All of our power supply contract costs are currently included in the rates we charge our customers. The risks associated with our power supply resources, including outage, curtailment, and other delivery risks, the timing of contract expirations, the volatility of wholesale prices, and other factors impacting our power supply resources and how they relate to customer demand are discussed below under Item 7a, "Quantitative and Qualitative Disclosure about Market Risk."

We also discuss other risks, including customer concentration risk related to our largest customer, International Business Machines Corporation ("IBM"), and contingencies that could have a significant impact on future operating results and our financial condition.

Growth opportunities beyond the Company's normal investment in its infrastructure are also discussed, and include a planned increase in our equity investment in Vermont Electric Power Company, Inc. ("VELCO") and an opportunity for increased sales of utility services.

In this section, we explain the general financial condition and the results of operations for the Company and its subsidiaries. This explanation includes:

* factors that affect our business;

* our earnings and costs in the periods presented and why they changed between periods;

* the source of our earnings;

* our expenditures for capital projects and what we expect they will be in the future;

* where we expect to get cash for future capital expenditures; and

* how all of the above affect our overall financial condition.

From time to time in this report, we may make statements that constitute “forward-looking statements” within the meaning of the “safe-harbor” provisions of the Private Securities Litigation Reform Act of 1995. Such statements are based on our then current expectations and are subject to a number of risks and uncertainties that could cause actual results to differ materially from those addressed in the forward-looking statements. In these statements, you may find words such as believes, expects, plans, or similar words. These statements are not guarantees of our future performance. There are risks, uncertainties and other factors that could cause actual results to be different from those projected. Some of the reasons the results may be different include:

* regulatory and judicial decisions or legislation and other regulatory risks
* energy supply and demand, outages and other power supply volume risks
* power supply price risks
* customer concentration risks
* pension and postretirement health care risks
* customer service quality
* changes in regional market and transmission rules
* contractual commitments
* credit risks, including availability, terms, and use of capital and counterparty credit quality
* general economic and business environment
* changes in technology
* nuclear and environmental issues
* alternative regulation and cost recovery (including stranded costs)
* weather

Additional risk factors that may cause such a difference are discussed in Item 7A, “Quantitative and Qualitative Disclosures About Market Risk” and elsewhere herein and are incorporated herein.

These forward-looking statements represent our estimates and assumptions only as of the date of this report.

Earnings Summary		**For the Years Ended**	
	2005	**2004**	**2003**
Consolidated diluted earnings per share of common stock	$ 2.12	$ 2.20	$ 2.02
Consolidated diluted earnings per share of common stock-continuing operations	$ 2.09	$ 2.10	$ 2.01
Consolidated return on average common equity	9.85 %	11.06 %	10.76 %

Earnings from continuing operations in 2005 were essentially unchanged compared with 2004. Increases in retail operating revenues during 2005 exceeded increases in power supply expenses. Retail operating revenues improved in 2005 because of a 1.9 percent rate increase that took effect at the beginning of 2005, increased sales of electricity to customers, and an increase in the number of customers we serve. Other operating expenses, maintenance expenses, depreciation and amortization, and transmission expenses also increased during 2005 compared with 2004, offsetting the increase in margins on the sale of electricity.

Retail operating revenues for 2005 increased by $9.6 million compared with the same period in 2004, reflecting the 2005 effects of a 1.9 percent retail rate increase, warmer summer weather, an increase in the number of Company customers, and increased sales of utility services to other utilities and large industrial and commercial customers. These increases were partially offset by recognition in 2004 of $3 million in revenue deferred under our 2003 Rate Plan. Under the Company's 2003 Rate Plan, approved by the VPSB in December 2003, rates remained unchanged in 2004 and the Company put into effect retail rate increases of 1.9 percent (generating approximately $4 million in added annual revenues) in January 2005 and 0.9 percent (generating approximately $2 million in added annual revenues) in January 2006. The 2003 Rate Plan also allowed the Company to carry unused deferred revenue totaling approximately $3 million to 2004 and to recognize this revenue to help to achieve its allowed rate of return during 2004.

Total retail megawatt hour sales of electricity increased by 1.9 percent in 2005, compared with the same period in 2004. Sales to residential and small commercial and industrial customers increased by 3.0 percent and 2.7 percent, respectively, while sales to large commercial and industrial customers increased by 0.3 percent in 2005. Revenues from the sale of utility services to other utilities and large industrial and commercial customers increased by approximately $4.3 million in 2005, compared with the prior year. Wholesale revenues in 2005 also increased by $5.6 million compared with 2004, reflecting substantially higher wholesale energy prices in 2005. Other operating expenses increased by $5.5 million in 2005, reflecting an increase of $4.3 million in utility services expense. The Company's utility services business is designed to recover some of its administrative and staffing costs from other parties, ultimately reducing costs to customers and improving financial results between rate cases.

Power supply expenses increased $6.0 million in 2005 compared with 2004 due to increased costs of market purchases to serve marginal load, increased purchases of power under the contract with Hydro Quebec, an increase in the cost of power under the power supply contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract"), and increased costs of transmission line losses and congestion charges allocated within the New England power pool by ISO New England ("ISO-NE"), the regional system operator. Congestion charges represent the cost of delivering energy to customers and reflect energy prices, customer demand, and the demands on transmission and generation resources. The Company paid an average market price of approximately $95 per megawatt hour for system purchases during hours when customer demand exceeded supply during 2005, compared to $57 per megawatt hour in the same period last year, inclusive of the effects of congestion and line losses. Our cost of market purchases in 2005 rose approximately $2.3 million accordingly. Increased hydro production and deliveries under long-term power supply contracts with Hydro Quebec and Vermont Yankee had a significant dampening effect on the increase in power supply expenses the Company experienced in 2005.

Maintenance expenses, depreciation and amortization, and transmission expenses also increased during 2005 compared with 2004. Maintenance expenses increased by $1.5 million, reflecting an increase in transmission and distribution line maintenance and maintenance of our gas turbines. Depreciation and amortization were $1.1 million higher than in the previous year, reflecting increased plant investments and a $539,000 increase in amortization of regulatory assets. Transmission expenses increased by $797,000 during 2005, compared with the prior year, as a result of an increase in charges allocated for system support in New England by ISO-NE, increased retail sales of energy and an increase in investments by Vermont Electric Power Company (VELCO), the entity that owns and operates most of the transmission grid in Vermont. The Company owns approximately 30 percent of VELCO.

Earnings from discontinued operations totaled $.03 per share in 2005 compared with $.10 per share in the prior year, reflecting diminished exposure to outstanding litigation against an inactive Northern Water Resources ("NWR") subsidiary that led to reversal of previously recorded reserves in 2004.

The Company accounts for its wholly-owned subsidiary, NWR, as a discontinued operation. NWR's assets and liabilities consist primarily of deferred tax assets and liabilities relating to a number of investments that the Company has discontinued, deactivated, sold in part or retained as passive minority interests. Remaining holdings include a minority equity investment in a wind project that usually, but not always, generates tax losses; minority interest in a manufacturer of waste treatment equipment; and some non-performing loans. All of these investments have been written off except for associated deferred tax amounts, net of applicable valuation allowances.

Earnings from continuing operations improved in 2004 primarily as a result of increased recognition of revenues previously deferred under a VPSB order described below, and from growth in retail sales of electricity to large and small commercial and industrial customers. Higher transmission expenses partially offset these benefits.

The VPSB's January 2001 rate order (the "2001 Settlement Order") allowed the Company to defer revenues of approximately $8.5 million, generated by leveling winter/summer rates during 2001, to help offset costs and realize our allowed rate of return during the 2001-2003 period. The 2003 Rate Plan permitted us to continue to defer and recognize these revenues in 2004. We recognized approximately $3.0 million of these deferred revenues to achieve our allowed rate of return during 2004, compared with approximately $1.1 and $4.5 million recognized in 2003 and 2002, respectively. At December 31, 2004, there were no remaining revenues deferred under the 2003 Rate Plan.

Retail operating revenues in 2004 increased by $6.4 million or 3.2 percent compared with 2003, reflecting an improving economy, including a modest growth in the number of customers served, and increased recognition of revenues deferred under the 2003 Rate Plan discussed above. Total retail megawatt hour sales of electricity increased by 1.8 percent in 2004, compared with the same period in 2003. Megawatt hour sales of electricity to large and small commercial and industrial customers increased by 3.3 percent and 2.0 percent, respectively, while sales to residential customers were flat when compared with 2003, reflecting milder and more normal weather conditions in 2004.

Wholesale revenues in 2004 decreased by $56.2 million compared with 2003, reflecting reduced sales of electricity under the Morgan Stanley Contract, an agreement designed to manage price risks associated with changing fossil fuel prices. The reduction in wholesale revenues did not adversely affect Company earnings in 2005 or 2004 and is not expected to adversely affect future operating results.

Power supply expenses in 2004 decreased $53.3 million compared with 2003 due to decreased wholesale sales of electricity, principally those associated with the Morgan Stanley Contract. Power supply expense also decreased due to reduced expenses to supply an option agreement with Hydro Quebec (the "9701 agreement"), and an increase in credits resulting from monthly financial transmission rights ("FTR") auctions conducted by ISO-NE designed to make regions with inadequate transmission and generation pay a premium for energy delivery.

Earnings from discontinued operations totaled $.10 per share in 2004 compared with $.01 per share in the prior year, reflecting diminished exposure to outstanding litigation against an inactive NWR subsidiary that led to reversal of previously recorded reserves.

Critical Accounting Policies

We believe our most critical accounting policies include the timing of expense and revenue recognition under the regulatory accounting framework within which we operate; the manner in which we account for certain power supply contracts that qualify as derivatives; revenue recognition, particularly as it relates to unbilled and deferred revenues; the assumptions that we make regarding our defined benefit pension and postretirement health care plans; and management judgments about the expected outcome of litigation for contingencies. These accounting policies, among others, affect significant judgments and estimates used in the preparation of our consolidated financial statements.

Regulatory Accounting

The accompanying consolidated financial statements conform to accounting principles generally accepted in the United States of America applicable to rate-regulated enterprises in accordance with Statement of Financial

Accounting Standards No. 71 ("SFAS 71"), "Accounting for Certain Types of Regulation." Under SFAS 71, the Company accounts for certain transactions in accordance with permitted regulatory treatment. As such, regulators may permit incurred costs or benefits, typically treated as expenses or income by unregulated entities, to be deferred and expensed or benefited in future periods. Costs are deferred as regulatory assets when the Company concludes that future revenue will be provided to permit recovery of the previously incurred cost. Revenue may also be deferred as regulatory liabilities that would be returned to customers by reducing future revenue requirements. The Company analyzes evidence supporting deferral, including provisions for recovery in regulatory orders, past regulatory precedent, other regulatory correspondence and legal representations. Management's conclusions on the recovery of regulatory assets represent a critical accounting estimate.

Conditions that could give rise to the discontinuance of SFAS 71 include increasing competition that restricts the Company's ability to recover specific costs, and a change in the manner in which rates are set by regulators from cost-based regulation to some other form of regulation.

In the event that the Company no longer satisfies the criteria under SFAS 71, the Company would be required to write off its regulatory assets, net of regulatory liabilities as set forth in the table below:

Regulatory assets and liabilities

	At December 31, 2005	2004
Regulatory assets:	(in thousands)	
Demand-side management programs	$ 5,835	$ 7,293
Purchased power costs	1,812	2,322
Pine Street barge canal	12,861	13,250
Power supply regulatory assets	30,135	22,821
Other regulatory assets	5,809	6,932
Total regulatory assets*	56,452	52,618
Regulatory liabilities:		
Accumulated cost of removal	21,105	19,806
Power supply regulatory liability	15,342	10,736
Other regulatory liabilities	6,513	4,012
Total regulatory liabilities	42,960	34,554
Regulatory assets net of regulatory liabilities	$ 13,492	$ 18,064

*Substantially all regulatory assets are being recovered in current rates effective January 1, 2005 and, with the exception of Pine Street Barge Canal and certain power contract related costs, include an associated return on investment.

The 2003 Rate Plan, approved by the VPSB in December 2003, provides for amortization and recovery of nearly all of the regulatory assets listed above, beginning January 1, 2005. The Pine Street Barge Canal regulatory asset is subject to amortization over a period of 20 years without a return on the remaining balance of the asset. Recovery of regulatory assets under the 2003 Rate Plan has eliminated much uncertainty regarding the valuation of these assets.

Derivatives

The power supply regulatory assets and liabilities represent the value of certain power supply contracts that must be marked to fair value as derivatives under current accounting rules. The fair value of derivative power supply positions can vary significantly based on assumptions, including the risk free interest rate, price volatility for the power supply contracts and expected average forward market prices. The Company records contract specified prices for electricity as expense in the period used, as opposed to fair market values reflected in the above table, in accordance with accounting required by a VPSB order. The power supply contract expenses are fully recovered in the rates we charge, and are discussed in more detail under Power Supply Derivatives.

Revenue Recognition

Our operating revenues are derived principally from retail sales of electricity at regulated rates. Revenue is recognized when electricity is delivered. The Company accrues utility revenues, based on estimates of electric service rendered and not billed at the end of an accounting period and net of estimates of electricity lost ("line losses") during transmission and distribution. The Company estimates its range of line losses at between 3.5 percent and 6 percent. The Company estimates that a substantial change of 1.5 percent (e.g., from 3.5 percent to 5 percent) in its line loss rate used for calculating its unbilled revenues would result in a pre-tax change of approximately $300,000.

The Company's earnings are capped at its allowed rate of return on equity of 10.5 percent. At year-end, the Company estimates its earnings based on its rate model. Costs that are not allowed for rate setting purposes reduce our earnings and ability to achieve our allowed rate of return on equity for our operations as a whole. We estimate the annual adverse effect of the earnings cap calculation on earnings at between zero and 15 cents per share. During 2005, the Company deferred $1.9 million of revenue pre-tax as required by the earnings cap calculation. Our earnings cap calculation is reviewed by the VPSB and is subject to change.

Defined Benefit Plans
The Company's defined benefit pension and postretirement health care plans' costs can vary significantly based on plan assumptions and results, including the following factors: interest rates, healthcare cost trends, return on assets and compensation cost trends. See Note G in the Notes to Consolidated Financial Statements for a discussion of sensitivities around certain defined benefit plan assumptions. Our funding level for our defined benefit plans has recently amounted to approximately 80 - 85 percent of our projected obligation, about average for the industry.

Contingencies
Management also exercises judgments about the expected outcome of litigation for contingencies. If the Company determines that it is probable that it will sustain a loss associated with pending litigation, regulatory proceedings or tax matters, and if it can estimate the likely amount of such loss, it will record a liability for that amount.

Our critical accounting policies are discussed further below under Item 7a, "Quantitative And Qualitative Disclosures About Market Risk," under "Liquidity and Capital Resources - Pension," in Note A, "Significant Accounting Policies," in Note G, "Pension and Retirement Plans" and in Note H, "Commitments and Contingencies."

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK
We consider our principal risks to include power supply risks, our regulatory environment (particularly as it relates to the Company's periodic need for rate relief), risks associated with our principal customer, IBM, benefit plan cost sensitivity to interest rates and healthcare cost inflation, and weather. Discussion of these and other risks, as well as factors contributing to mitigation of these risks, follows.

Power Supply Risks.
Power Contract Commitments - The Company meets more than 90 percent of its customer demand through a series of long-term physical and financial contracts. The Company's most significant power supply contracts are the Hydro Quebec-Vermont Joint Owners ("VJO") Contract (the "VJO Contract") and the Vermont Yankee Nuclear Power Corporation ("VYNPC") Contract (the "VYNPC Contract"), which together cover approximately 75 percent of our retail load. The Company has also entered into a contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract") designed to manage wholesale electricity price risks associated with changing fossil fuel prices. The Morgan Stanley Contract supplies approximately an additional 17 percent of our load and expires December 31, 2006. The VJO and VYNPC contracts are summarized in the following table. The Morgan Stanley Contract terms are subject to a confidentiality agreement.

	2005 MWh	2005 $/MWh	2004 MWh	2004 $/MWh	2003 MWh	2003 $/MWh	Contract Expires
VJO Contract	680,984	$ 69.61	605,718	$ 74.47	664,225	$ 69.81	2015
VYNPC Contract	816,989	$ 39.67	764,010	$ 43.63	884,585	$ 43.08	2012

The Company's current purchases under the VJO Contract with Hydro Quebec are as follows: (1) Schedule B -- 68 megawatts of firm capacity and associated energy for twenty years beginning in September 1995; and (2) Schedule C3 -- 46 megawatts of firm capacity and associated energy at any time for 20 years, beginning in November 1995.

In 1996, the Company entered into an agreement with Hydro Quebec ("the 9701 agreement") under which Hydro Quebec paid $8.0 million to the Company in 1997 and we provided Hydro Quebec options for the purchase of power in specified maximum amounts through 2015, as discussed below under "Power Supply Derivatives."

On July 31, 2002, VYNPC completed the sale of its nuclear power plant to Entergy Nuclear Vermont Yankee LLC ("ENVY"). As part of the sale transaction, VYNPC entered into a Power Purchase Agreement ("PPA") with ENVY under which ENVY is obligated to provide 20 percent of the plant output to the Company through 2012, which represents approximately 35 percent of our energy requirements. Prices under the PPA generally range from $39 to $45 per MWh. The PPA contains a provision known as the "low market adjuster," which calls for a downward adjustment in the price if market prices for electricity fall by defined amounts beginning in November 2005. If market prices rise, however, PPA prices are not adjusted upward in excess of the contract price. The Company remains responsible for procuring replacement energy at market prices during periods of scheduled or unscheduled outages at the ENVY plant. Current market prices are far above these levels so we do not expect the low market adjuster to affect contract pricing in the near future. We no longer bear the operating costs and risks associated with running and decommissioning the plant.

The Company entered into the Morgan Stanley Contract in 1999. In August 2002, the Morgan Stanley Contract was modified and extended to December 31, 2006. The Morgan Stanley Contract price is substantially below current market prices.

Under the Morgan Stanley Contract, on a daily basis, and at Morgan Stanley's discretion, we sell power to Morgan Stanley from part of our portfolio of power resources at pre-defined operating and pricing parameters. Morgan Stanley sells to the Company, at a pre-defined price, power sufficient to serve pre-established load requirements. We remain responsible for resource performance and availability. The Morgan Stanley Contract provides no coverage against major unscheduled power supply outages. Beginning January 1, 2004, the Company reduced the power that it sells pursuant to the Morgan Stanley Contract. The output of some of our power-supply resources, including purchases pursuant to our Hydro Quebec and VYNPC contracts, which were sold to Morgan Stanley through 2003, are no longer included in the Morgan Stanley Contract. This reduction in sales to Morgan Stanley reduced wholesale revenues by approximately $56.2 million during 2004 when compared with 2003, and correspondingly reduced power supply expense by a similar amount. This change did not adversely affect the Company's operating results or its opportunity to earn a fair rate of return during 2004 or 2005.

Power Supply Price Risk - The Company meets most of its customer demand through a series of long-term physical and financial contracts. All of the Company's power supply contract costs are currently being recovered through rates approved by the VPSB. The Company records the annual cost of power obtained under long-term contracts as operating expenses. There are occasions when the Company's available supply of electricity is insufficient to meet customer demand. During those periods, electricity is purchased at market prices. The Company must also purchase energy at market prices for outages or other delivery interruptions under its principal supply contracts.

We expect more than 90 percent of our estimated load requirements through 2006 to be met by our contracts and generation and other power supply resources. These contracts and resources significantly reduce the Company's exposure to volatility in wholesale energy market prices.

A primary factor affecting future operating results is the volatility of the wholesale electricity market. Implementation of New England's wholesale market for electricity has increased volatility of wholesale power prices. Periods frequently occur when weather, availability of power supply resources and other factors cause significant differences between customer demand and electricity supply. Because electricity cannot be stored, in these situations the Company must buy from or sell the difference into a marketplace that has experienced volatile energy prices. Market price trends also may make it more difficult to extend or enter into new power supply contracts at prices that avoid the need for rate relief. Vermont does not have an automatic fuel adjustment clause or similar mechanism to adjust rates for higher energy costs without prior regulatory approval.

The Company is charged for a number of power supply ancillary services, including costs for congestion, reserves and regulation that vary in part due to changes in the price of energy. Congestion charges represent the cost of delivering energy to customers and reflect energy prices, customer demand, and the demands on transmission and generation resources. The method of settling the cost of congestion and other ancillary services is administered by ISO New-England and is subject to change. During periods of high prices, ancillary charges are volatile and can adversely impact earnings to a significant degree. Some energy that is purchased by the Company and delivered over transmission and distribution lines is lost during the delivery process ("line losses"). All electric companies experience line losses, which vary according to the equipment employed, temperature and load demands. The cost of line losses varies with the price of energy, which increased substantially during 2005. In periods of high price volatility, we estimate that our power supply expenses could vary in excess of $1 million annually due to changes in line loss and congestion costs.

ISO-NE supports locational capacity payments (“LICAP”) to generators in an effort to differentiate the price generators receive for capacity at different locations within New England. ISO-NE believes that proposed higher capacity payments in constrained areas will encourage the development of new generation where needed. ISO-NE has petitioned FERC for approval of LICAP at levels that are expected to result in substantially higher capacity payments to generators beginning December 1, 2006. The changes have been disputed by numerous parties for a variety of reasons. FERC has not yet approved ISO-NE’s LICAP proposal. In October 2005, FERC initiated a settlement process to consider alternatives to the LICAP proposal. Under ISO-NE’s current LICAP proposal, Vermont is expected to fare better than many New England states since Vermont has not restructured and many of its utilities, including the Company, have specified power supply resources that meet their present needs. Therefore, requirements for capacity in Vermont would largely consist of obtaining resources for incremental, as opposed to existing, load. Even incrementally, future LICAP amounts for load growth beyond 2006 could be material, and if so, would be expected to increase Company rate requirements accordingly. Based on the current ISO-NE proposal, the Company estimates that the 2007 impact of LICAP price increases would raise our power supply expenses by between $300,000 and $400,000 pre-tax.

The Company has established a risk management program designed to mitigate some of the potential adverse cash flow and income statement effects caused by power supply risks, including credit risks associated with counterparties. Transactions permitted by the risk management program include futures, forward contracts, option contracts, swaps and the sale or purchase of transmission congestion rights. These transactions are used to hedge the risk of fossil fuel and spot market electricity price increases. Some of these transactions present the risk of potential losses from adverse changes in commodity prices. Our risk management policy specifies risk measures, the amount of tolerable risk exposure and authorization limits for transactions. Most of our principal power supply contract counter-parties and generators, including Hydro Quebec and Morgan Stanley, currently have investment grade credit ratings. ENVY does not have an investment grade rating.

Power Supply Derivatives - The Morgan Stanley Contract is used to hedge our power supply costs against increases in fossil fuel prices. The Morgan Stanley Contract is a derivative under Statement of Financial Accounting Standards No. 133 ("SFAS 133"). Management has estimated the fair value of the future net benefit of this agreement at December 31, 2005 to be approximately $15.1 million.

The Company is unable to predict the price, contract duration or terms of any future power supply contract that could replace the Morgan Stanley Contract after it expires on December 31, 2006. However, current market prices are substantially in excess of the Morgan Stanley Contract, and we expect the replacement cost of this contract to increase substantially and to increase the Company’s need for rate relief in 2007.

The Company's 9701 agreement with Hydro Quebec grants Hydro Quebec an option to call power at prices that are now expected to be below estimated future wholesale market prices. Commencing April 1, 1998, and effective through the term of the VJO Contract, which ends in 2015, Hydro Quebec may purchase up to 52,500 MWh on an annual basis ("option A") at the VJO Contract energy price. The cumulative amount of energy that may be purchased under option A may not exceed 950,000 MWh (52,500 MWh in each contract year). We expect Hydro Quebec to exercise Option A each year.

Over the same period, Hydro Quebec could exercise an option to purchase up to 200,000 MWh on an annual basis at the VJO Contract energy price ("option B"). The cumulative amount of energy that could be purchased under option B could not exceed 600,000 MWh. Hydro Quebec called its remaining entitlements of approximately 34,000 MWh under option B during 2005.

Hydro Quebec exercised options A and B for 2003, 2004 and 2005, and the Company purchased replacement power at a net cost of $4.5 million, $3.2 million and $2.7 million, respectively. The Company has also covered option A during 2006 at a net cost of $7.4 million. Hydro Quebec's call for 2006 was made during the fourth quarter of 2005 for delivery during January and February, timed to take advantage of extremely high forward energy prices resulting from the effects of hurricanes Katrina and Wilma that interrupted gas production in the Gulf of Mexico. Energy prices in the Northeast are heavily dependent upon natural gas prices. In February 2006, the Company requested an accounting order from the VPSB allowing us to defer in 2006 extraordinary hurricane-related costs, expected to be incurred in 2006, of up to approximately $3.7 million. The VPSB granted our request in February 2006 that we expect to result in a regulatory asset of approximately $2.4 million. Collectability of these amounts will be determined in our next retail rate filing, expected to be filed and decided in 2006. If the VPSB denies any or all of the amounts requested, these amounts would be charged against pre-tax income immediately.

The 9701 agreement is a derivative and is effective through 2015. Management's estimate of the fair value of the future net cost for this agreement at December 31, 2005 is approximately $30.1 million. We sometimes use forward contracts to hedge forecasted calls by Hydro Quebec under the 9701 agreement and treat such contracts as derivatives under SFAS 133.

The Company has other less significant derivative positions, including forward sales for the months of March - May 2006 made to capture forward energy prices that were high by historical standards, and financial transmission rights ("FTRs") that hedge against risks related to the cost of delivering energy from its generation point to where it is consumed.

The table below presents assumptions used to estimate the fair value of the Morgan Stanley Contract, the 9701 agreement and forward sale contracts. The forward prices for electricity used in this analysis are consistent with the Company's current long-term wholesale energy price forecast.

	Option Value Model	Risk Free Interest Rate		Price Volatility		Average Forward Price	Contract Expires
Morgan Stanley Contract	Deterministic	4.4	%	42	%$	97	2006
9701 agreement	Black-Scholes	4.4	%	29%-10	%$	69	2015
Forward sale contracts	Deterministic	n/a		0	%$	96	2006

The table below presents the Company's estimated market risk of the Morgan Stanley and Hydro Quebec derivatives and forward sale contract derivatives, estimated as the potential loss in fair value resulting from a hypothetical ten percent adverse change in wholesale energy prices, which nets to $2.5 million. Actual results may differ materially from the table illustration.

Commodity Price Risk	At December 31, 2005			
		Fair Value		Market Risk
(in thousands)				
Morgan Stanley Contract	$	15,104	$	1,488
9701 agreement		(30,135)		(3,707)
Forward sale contracts		238		(273)
	$	(14,793)	$	(2,492)

Under an accounting order issued by the VPSB, changes in the fair value of derivatives are deferred. If a derivative instrument were terminated early because it is probable that a transaction or forecasted transaction will not occur, any gain or loss would be recognized in earnings immediately. For derivatives held to maturity, the earnings impact is recorded in the period that the derivative is sold or matures.

Other Power Supply Risk - Under the VJO Contract, Hydro Quebec has the right to reduce the load factor from 75 percent to 65 percent a total of three times over the life of the contract. Hydro Quebec exercised the first of these load reduction options, effective for the year 2003. Hydro Quebec's exercise of this option increased power supply expense during 2003 by approximately $1.2 million. During 2003, Hydro Quebec exercised its second option to reduce the load factor for 2004, which increased power supply expense in 2004 by approximately $1.8 million. Hydro Quebec exercised its third and final option in 2004 to reduce deliveries occurring principally during 2005, which increased 2005 power supply expense by an estimated $3.9 million. The Vermont Joint Owners, including the Company, retain two options to increase the load factor to 80 percent from 75 percent after 2005, and the Company exercised the first of these options in the fourth quarter of 2005 for delivery effective November 1, 2005 to October 31, 2006.

Hydro Quebec also retains the right to curtail annual energy deliveries under the VJO Contract by 10 percent up to five times, over the 2001 to 2015 period, if documented drought conditions exist in Quebec. Hydro Quebec has not exercised this right and has not communicated to the Company any present intention to do so.

We sometimes experience energy delivery deficiencies under the VJO Contract as a result of outages or other problems with the transmission interconnection facilities over which we schedule deliveries. When such deficiencies occur, we purchase replacement energy on the wholesale market, usually at prices that are substantially higher than VJO Contract energy costs. VJO energy prices are less than $30 per megawatt hour, while forward prices in 2006 are in excess of $70 per megawatt hour. We expect to purchase in excess of 700,000 megawatt hours during 2006, so any significant deficiencies in deliveries would increase power supply costs materially.

Our VJO contract contains cross default provisions that allow Hydro Quebec to invoke "step-up" provisions under which the other Vermont utilities that are also parties to the contract would be required to purchase their proportionate share of the power supply entitlement of any defaulting utility. The Company is not aware of any instance where this provision has been invoked by Hydro Quebec.

In accordance with guidance set forth in FASB Interpretation No. 45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others ("FIN 45"), the Company is required to disclose the "maximum potential amount of future payments (undiscounted) the guarantor could be required to make under the guarantee." Such disclosure is required even if the likelihood of triggering the guarantee is remote. In regards to the "step-up" provision in the VJO Contract, the Company must assume that all other members of the VJO simultaneously default in order to estimate the "maximum potential" amount of future payments. The Company believes this is a highly unlikely scenario given that the majority of VJO members are regulated utilities with regulated cost recovery. Each VJO participant has received regulatory approval to recover the cost of this purchased power. Despite the remote chance that such an event could occur, the Company estimates that its undiscounted purchase obligation would be approximately $832 million for the remainder of the contract, assuming that all other members of the VJO defaulted by January 1, 2006 and remained in default for the duration of the contract. In such a scenario, the Company would then own the power and could seek to resell the energy in the wholesale power markets and recovery the losses, if any, and/or recover its costs from the defaulting members or its retail customers. The range of outcomes (full cost recovery, potential loss or potential profit) would be highly dependent on Vermont regulation and wholesale market prices at the time.

During 2002, we estimate that the Company paid an additional $1.0 million for replacement power as the result of an unscheduled outage at the Vermont Yankee nuclear power plant. During 2003, another unscheduled outage resulted in the Company’s deferral of approximately $500,000 of added power supply costs. While the Vermont Yankee plant has had an excellent operating record, future unscheduled outages could occur at times when replacement energy costs are well above VYNPC Contract costs. Based on current forward prices, we estimate that the Company could potentially have to pay increased costs of approximately $100,000 for each day that the Vermont Yankee plant experienced an unscheduled outage. Historically, the VPSB has allowed the Company to defer, rather than expense, the higher costs resulting from extraordinary outages at the plant. Since the Company no longer owns an interest in the Vermont

Yankee nuclear plant, we are not responsible for any fixed costs at the plant, the costs of decommissioning the plant, nor are we responsible for any plant repairs or maintenance costs during outages.

On June 18, 2004, a fire in the electrical conduits leading to a transformer outside the Vermont Yankee plant resulted in a shutdown of the plant. The outage ended on July 7, 2004. In response to the Company's request, the VPSB issued a final accounting order allowing the Company to defer its incremental replacement power costs during the outage totaling approximately $500,000. The order also instructs the Company to apply any proceeds received under a Ratepayer Protection Plan ("RPP") to reduce the balance of deferred replacement power costs.

The RPP was a part of ENVY's request to uprate or increase the output of the Vermont Yankee nuclear plant that was approved by the VPSB. Under the RPP, we have indemnification rights to between approximately $550,000 and $1.6 million to recover uprate-related reductions in output for the three-year period beginning in May 2004 and ending after completion of the uprate (or a maximum of three years), depending on future wholesale energy market prices. ENVY disputes that the fire was uprate-related. The Company has petitioned the VPSB to resolve the dispute.

The Vermont Yankee plant received final approval for uprating from the Nuclear Regulatory Commission on March 2, 2006. The plant production will now be gradually increased and monitored as the plant progresses to its new full-power output of approximately 640 megawatts. After the Vermont Yankee plant uprating is completed, our percentage of energy output under Vermont Yankee’s contract with ENVY would decline proportionately such that we would receive the same quantity of energy from the plant. In the event that ENVY were later derated, then our rights to energy output would decline proportionately to the derating. If this were to occur, we estimate it would have a material adverse effect on power supply costs. In this event we would seek recovery of these costs from the VPSB.

ENVY has announced that, under current operating parameters, it will exhaust the capacity of its existing nuclear waste storage pool in 2007 or 2008 and will need to store nuclear waste in so-called “dry fuel storage” facilities to be constructed on the site. Vermont law requires ENVY to obtain approval of the Vermont State legislature, in addition to VPSB approval, to construct and use such dry fuel storage facilities. ENVY received approval from the legislature in 2005 and is awaiting approval from the VPSB. If ENVY is unsuccessful in receiving favorable regulatory approval, ENVY has announced that it could be required to shut down the Vermont Yankee plant between 2007 and 2008. If the Vermont Yankee plant is shut down in 2007 or 2008, we would have to acquire substitute baseload power resources, comprising approximately 35 percent of our load. At projected forward market prices at December 31, 2005 for 2006, we estimate the annual incremental cost (in excess of the projected costs of power under our power supply contract for output from the Vermont Yankee plant) would be approximately $47 million per year. Recovery of those increased costs in rates would require a rate increase of approximately 23 percent.

Regulatory Risk - Management believes that fair regulatory treatment is crucial to maintaining its financial stability, including its ability to attract capital. Principal regulatory risks for the Company relate to the relative frequency and magnitude of rate increases sought in contested retail rate filings. Regulatory lag and uncertainty regarding the outcome of rate proceedings contributes to the risk that we will not achieve our allowed rate of return in any given year. The Company expects to request a retail rate increase of between ten and fifteen percent in 2006 to be effective January 1, 2007. Principal reasons for the expected rate increase request include forecasted higher replacement energy costs upon expiration of the Morgan Stanley Contract on December 31, 2006, increased energy costs for uncovered load obligations and a forecasted increase in transmission expense. Forecasted amounts could change materially based on energy prices, the timing of transmission investments and other factors. For example, every $8 per MWh change in replacement energy costs for the Morgan Stanley Contract will result in a 1 percent increase or decrease in the magnitude of the rate increase sought by the Company for 2007. Price changes of $8 per MWh or more on a weekly or monthly basis commonly occurred in 2005.

Electric rates in Vermont are currently among the lowest in the region due in large part to Vermont utilities’ relatively low cost, long-term contracts with VYNPC and Hydro Quebec. Since 2001, the Company’s need for rate relief has been modest, reflecting only scheduled rate increases of 1.9 percent in 2005 and 0.9 percent in 2006 under the 2003

Rate Plan. In August 2002, we extended our Morgan Stanley Contract before wholesale market power supply prices increased and we have been able to pass those benefits along to our customers. The magnitude of the retail rate increase that the Company expects to seek for 2007, while significant, is below that of many other utility companies in Vermont and New England. Our retail rates through 2006 are set by our 2003 Rate Plan.

Vermont does not have a fuel or purchased-power adjustment clause that would allow increases in power supply costs to be recovered immediately in the rates we charge customers. Historically, however, the VPSB has allowed electric utilities to defer material unexpected increases in power supply costs to future periods to permit recovery in future rates. Obtaining a change in retail rates generally requires a rate proceeding that lasts for a period of eight and one half months. Vermont law also allows electric utilities to seek temporary rate increases if deemed necessary by the VPSB to provide adequate and efficient service or to preserve the viability of the utility. Additionally, Vermont law permits alternative regulation that could potentially provide mechanisms to adjust rates for changes in power supply expense, if approved by the VPSB. The Company expects to pursue an alternative regulation plan for 2007 that would contain a power supply and transmission expense rate adjustment clause.

Electric utility rates in Vermont are set based on the utility’s cost of service. As a result, Vermont electric utilities are subject to certain accounting standards that apply only to regulated businesses. "SFAS 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.

The Company has recognized revenues deferred under previous regulatory orders to help it earn a fair rate of return (see "Earnings Summary"). The Company’s ability consistently to achieve its allowed rate of return is likely to be more uncertain prospectively due to the absence of available deferred revenues, unless it secures appropriate and adequate rate increases to cover its costs of operation.

Vermont is the only state in the New England region that has not adopted some form of electric industry restructuring. The Company, like all other electric utilities in Vermont, accordingly operates as a vertically integrated electric utility, with the obligation to serve all customers in our service territory with electrical transmission, distribution and energy supplies sufficient to satisfy customer load requirements.

Customer Concentration Risk - IBM, the Company’s largest customer, operates a manufacturing facility in Essex Junction, Vermont. IBM’s electricity requirements for its facility accounted for approximately 23.5, 24.1 and 24.1 percent of the Company’s retail MWh sales in 2005, 2004 and 2003, respectively, and 15.3, 16.2 and 16.6 percent of the Company’s retail operating revenues in 2005, 2004 and 2003, respectively. No other retail customer accounted for more than one percent of the Company’s revenue in any year.

IBM has reduced its Vermont workforce by approximately 2,500 since 2001, to a level of approximately 6,000 employees. Company revenue from sales of electricity to IBM decreased by approximately $95,000 in 2005 compared with 2004. Company revenue from sales of electricity to IBM increased by approximately $350,000 in 2004 compared with 2003. Our operating results are not adversely impacted by reductions in sales to IBM because IBM’s retail rates have recently been below wholesale market prices. We are not aware of any plans by IBM to further reduce production at its Vermont facility. We currently estimate, based on a number of projected variables, that a hypothetical shutdown of the IBM facility, inclusive of the tertiary effects on commercial and residential customers, would not necessitate retail rate increases because the Company could sell contracted power supply resources into the wholesale market at rates in excess of those charged to IBM. This estimate would change materially as a result of any significant reductions in energy prices or increases in retail rates paid by IBM.

Pension and Postretirement Health Care Risk - Other critical accounting policies involve the Company’s defined benefit pension and postretirement health care benefit plans. The reported costs of these plans depend upon numerous factors relating to actual plan experience and assumptions of future experience.

Pension and postretirement health care costs are affected by actual employee demographics, Company contributions to the plans, earnings on plan assets and, for our postretirement health care plan, health care cost trends. The Company contributed approximately $2.0 million, $2.2 million and $3.5 million to its defined benefit plans during 2005, 2004 and 2003, respectively, and we expect to contribute approximately $2.0 million during 2006 and in future years.

Our pension and postretirement health care benefit plan assets consist of equity and fixed income investments. Fluctuations in actual equity market returns, as well as changes in general interest rates, may increase or decrease costs in future periods. Changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded defined benefit plan costs.

On December 17, 2003, the Company’s employees ratified a four-year labor agreement that provides annual wage increases of between 3.5 and 4 percent and improved 401(k) and pension benefits for employees. This labor agreement caps future postretirement healthcare employee benefits provided by the Company for the majority of the present workforce. The cap on postretirement healthcare benefits is set approximately 13 percent above 2003 costs and grows at a 3 percent annual rate. This cap is expected to reduce the rate at which postretirement healthcare expenses grow in the future.

As a result of our plan asset experience, at December 31, 2002, the Company was required to recognize an additional minimum liability of $2.4 million, net of applicable income taxes. The liability was recorded as a reduction to common equity through a charge to Other Comprehensive Income ("OCI"). Favorable pension plan investment returns during 2003 reduced the OCI charge and related net liability by $587,000. In 2004 and 2005, a reduction in the pension plan's discount rate was primarily responsible for increasing the OCI charge and related net liability by $566,000 and $910,000, respectively. The 2005 and 2004 OCI charges and the 2003 OCI benefit had only an indirect effect on net income by adjusting the amount of equity used in the allowed rate of return on equity calculation.

Customer Service Quality - The Company has agreed to customer service performance requirements that impose penalties up to approximately $750,000 in the event that the Company does not achieve certain goals. The Company has not only achieved the performance requirement metrics, but typically exceeds the measurements. The Company continues to enhance its use of technology to improve its performance and does not expect its measurements to fall below the prescribed limits.

Weather - The Company periodically uses weather insurance to mitigate some of the risk of lost electricity sales caused by unfavorable weather conditions. The Company did not procure coverage for 2005 since forward energy prices approximated average retail rate levels.

Results of Operations

Operating Revenues and MWh Sales - Operating revenues, megawatt hour ("MWh") sales and number of customers for the years ended 2005, 2004 and 2003 were as follows:

	For the Years ended December 31,		
	2005	**2004**	**2003**
(dollars in thousands)			
Operating Revenues			
Retail*	$ 207,912	$ 203,218	$ 198,717
Sales for Resale	28,298	22,652	78,901
Other	9,650	4,704	2,852
Total Operating Revenues	$ 245,860	$ 230,574	$ 280,470
MWH Sales-Retail	2,008,250	1,969,925	1,934,340
MWH Sales for Resale	368,317	411,769	2,287,039
Total MWH Sales	2,376,567	2,381,694	4,221,379

**Retail revenues include $3.0 million and $1.1 million of deferred revenue recognized for 2004 and 2003, respectively, and were reduced by a deferral of $1.9 million of revenue for 2005.*

Average Number of Customers

	For the Years ended December 31,		
	2005	**2004**	**2003**
Residential	76,481	75,507	74,693
Commercial and Industrial	13,779	13,539	13,369
Other	60	62	65
Total Number of Customers	90,320	89,108	88,127

Comparative changes in operating revenues are summarized below:

Change in Operating Revenues	**2004 to 2005**	**2003 to 2004**	**2002 to 2003**
(In thousands)			
Retail Rates	$ 726	$ (912)	$ 6,471
Retail Sales Volume	3,968	(1,423)	(512)
Resales and Other Revenues	10,592	8,197	(14,815)
Increase (Decrease) in Operating Revenues	$ 15,286	$ 5,862	$ (8,856)

In 2005, total retail revenues increased 4.7 million or 2.6 percent compared with 2004, due to:

* Increased retail residential revenues of $3.5 million, or 4.7 percent, arising from a 3.0 percent increase in sales of electricity and a 1.9 percent retail rate increase effective January 1, 2005; and

* Increased retail small commercial and industrial ("C&I") revenues of $3.4 million, or 4.6 percent, arising from a 2.7 percent increase in sales of electricity and a 1.9 percent retail rate increase effective January 1, 2005; and

* Increased retail large C&I revenues of $1.2 million or 2.4 percent, arising from a 0.3 percent increase in sales of electricity and a 1.9 percent retail rate increase effective January 1, 2005.

These increases were partially offset by $3.0 million in deferred revenues recognized in 2004 under the 2003 Rate Plan.

Wholesale revenues increased by $5.6 million in 2005, compared with the prior year, reflecting substantially higher market prices for electricity. These higher prices also affected the prices paid for wholesale market purchases.

Other operating revenue more than doubled, increasing revenue by $4.9 million and reflected a $4.3 million increase from the sale of utility services to other utilities and large industrial customers. Other operating expense increased by a similar amount, reflecting the cost of sales for these activities.

In 2004, retail and other revenues increased $6.4 million or 3.2 percent compared with 2003, due to:

* An increase of $1.9 million in recognition of revenues deferred under the 2003 Rate Plan;

* A 3.3 percent increase in megawatt hour sales to large commercial and industrial customers resulting in a $1.4 million increase in revenue; and

* A 2.0 percent increase in megawatt hour sales to small commercial and industrial customers resulting in a $1.0 million increase in revenue.

Residential retail revenues and megawatt hour sales of electricity were up only 0.1 percent in 2004, compared with 2003. We experienced residential customer growth in 2004, but 2004 weather conditions were less favorable for electricity sales than 2003.

Wholesale revenues decreased in 2004 by $56.2 million, or 71.3 percent, compared with 2003, reflecting reduced sales of electricity under the Morgan Stanley Contract. The reduction in sales under the Morgan Stanley Contract did not adversely affect the Company's earnings in 2004 and is not expected to adversely affect the Company's earnings in future years.

Power Supply Expenses - Power supply expenses constituted 65.3, 67.5 and 74.4 percent of total operating expenses for the years 2005, 2004 and 2003, respectively. Most of the decrease is attributable to reduced purchases and sales of electricity under the Morgan Stanley Contract.

Power supply expenses increased by $6.0 million in 2005 when compared with 2004, and resulted from the following:

* A $2.3 million increase in the cost of market purchases caused primarily by higher wholesale market prices ($1.4 million) and a reduction of credits for the auction of transmission rights allocated by ISO-NE ($840,000);

*

A $2.3 million increase in power supply expenses under agreements with Hydro Quebec caused by increased megawatt hour purchases of electricity;

* A $1.5 million increase in purchases from Morgan Stanley caused primarily by an increase in contract prices; and

* A $654,000 increase in the costs of electricity supplied by independent power producers caused by production increases due to higher levels of precipitation.

These increases were partially offset by a $922,000 decrease in the cost of power under our contract with Vermont Yankee.

Power supply expenses decreased by $53.3 million or 27.0 percent in 2004 when compared with 2003, and resulted from the following:

* An estimated $56.2 million decrease in the cost of power purchased for resale resulting primarily from the restructuring of the Morgan Stanley Contract described above;

* A $1.8 million increase in credits from the ISO-NE resulting from FTR auctions designed to make congested regions pay a premium for energy delivery, and credits for certain Company generation; and

* A $1.3 million decrease in the net cost of our 9701 agreement with Hydro Quebec.

These decreases were partially offset by increased power supply expenses from the following:

* A $1.9 million increase in purchases to supply increased retail sales;

* An estimated $1.5 million in purchases to replace reduced energy deliveries under the VJO Contract as a result of problems with the transmission interconnection facilities over which we schedule deliveries; and

* An $851,000 increase in the contract price per megawatt hour of electricity purchased under the Morgan Stanley Contract.

Other Operating Expenses - Other operating expenses increased $5.5 million, or 28.3 percent, in 2005 compared with 2004, primarily as a result of a $4.3 million increase in expenses associated with the sale of utility services and an $852,000 increase in administrative and general expenses.

Other operating expenses in 2004 increased $1.8 million, or 10.0 percent, in 2005 compared with 2004, primarily as a result of an increase in expenses associated with the sale of utility services.

Transmission Expenses - Transmission expenses increased $797,000, or 5.1 percent, in 2005 compared with 2004 resulting from a $400,000 increase in system-wide allocation of costs associated with voltage control and reactive power (“VAR”) in New England. The remainder of the increase is due primarily to increased sales of energy and investment in VELCO transmission facilities allocable to the Company.

Transmission expenses increased $873,000, or 5.9 percent, in 2004 compared with 2003, due to increased charges allocated by ISO-NE for VAR in New England and engineering studies related to substation and transmission design evaluations. The Company’s relative share of transmission expenses varies with the peak demand recorded on Vermont’s transmission system. The Company’s share of those expenses increased due to its increased load growth, relative to other Vermont utilities, and also because of increased transmission investment by VELCO.

ISO-NE was created to manage the operations of the New England Power Pool ("NEPOOL"), effective May 1, 1999. ISO-NE operates a market for all New England states for purchasers and sellers of electricity in the deregulated wholesale energy markets. Sellers place bids for the sale of their generation or purchased power resources and if demand is high enough the output from those resources is sold.

ISO-NE implemented its Standard Market Design ("SMD") plan governing wholesale energy sales in New England on March 1, 2003. SMD includes a system of locational marginal pricing of energy, under which prices are determined by zone, and based in part on transmission congestion experienced in each zone. Currently, the State of Vermont constitutes a single zone under the plan.

FERC has granted approval to ISO-NE to become a regional transmission organization ("RTO") for New England. On February 1, 2005, ISO-NE commenced operations as the RTO, providing regional transmission service in New England, with operational control of the bulk power system and responsibility for administering wholesale markets. Commencing with implementation of the RTO, costs associated with certain transmission facilities, known as the Highgate Facilities, of which the Company is a part owner, will be phased into region-wide rates over a 5-year period. When fully phased in, we estimate that this "roll-in" of the Highgate facilities will achieve approximately $1.4 million in annual transmission costs savings for the Company.

VELCO, the owner and operator of Vermont’s principal electric transmission system assets, has proposed a project to substantially upgrade Vermont's transmission system (the "Northwest Reliability Project"), principally to support reliability and eliminate transmission constraints in northwestern Vermont, including most of the Company's service territory. We own approximately 29 percent of VELCO. In January 2005, the project received regulatory approval from the VPSB. The project is estimated to cost approximately $200 million through 2008. VELCO intends to finance the costs of constructing the Northwest Reliability Project in part through increased equity investment. In October 2004, the Company invested $4.6 million in VELCO to support this project and other transmission projects. The Company plans to invest up to $26 million additionally in VELCO through 2008, for the same purpose, assuming that VELCO maintains a capital structure of 75 percent debt and 25 percent equity. Under current NEPOOL and ISO-NE rules, which require qualifying large transmission project costs to be shared among all New England utilities, approximately 95 percent of the pool transmission facility costs of the Northwest Reliability Project will be allocated throughout the New England region, with Vermont utilities responsible for approximately 5 percent of allocated costs. Vermont utilities are required to pay 5 percent of pool transmission facility upgrades in other New England states.

Maintenance Expenses - Maintenance expense increased $1.5 million or 15.4 percent in 2005 compared with 2004, due to a $641,000 increase in maintenance expenditures on gas turbines and a $486,000 increase in distribution expenses, principally for right-of-way maintenance programs.

Maintenance expenses increased $25,000 or 0.2 percent in 2004 compared with 2003 due to increased expenditures on right-of-way maintenance programs offset by decreased expenditures related to gas turbine maintenance.

Depreciation and Amortization - Depreciation and amortization expense increased $1.1 million in 2005 or 8.2 percent compared with 2004 due to a $604,000 increase in depreciation of utility plant in service and a $539,000 increase in amortization of conservation expenditures.

Depreciation and amortization expense increased $128,000, or 0.9 percent, in 2004 compared with 2003 due to increases in depreciation of utility plant in service partially offset by decreased amortization of software costs.

Taxes other than income - Taxes other than income taxes decreased $98,000, or 1.5 percent, in 2005 compared with 2004 due to a $238,000 decrease in property tax offset partially by a $144,000 increase in gross revenue tax.

Taxes other than income taxes decreased $210,000 in 2004, or 3.0 percent, compared with 2003 due to decreased property tax expense.

Income Taxes - Income tax expense decreased $86,000, or 1.5 percent, in 2005 compared with 2004 due to a decrease in the Company's pre-tax income.

Income tax expense increased $642,000, or 12.5 percent, primarily due to an increase in pre-tax income in 2004 compared with 2003.

Total Other Income (net of other deductions) - Total other income decreased $362,000, or 17.4 percent, in 2005 compared with 2004 primarily due to $402,000 of one-time gains in 2004 on the sale of non-utility property, and a decrease of $420,000 in equity returns capitalized on regulatory assets in 2005, partially offset by increased earnings of VELCO.

Other income and deductions increased $8,000 in 2004 compared with 2003 due primarily to sales of non-utility property offset by reduced earnings on investment in Vermont Yankee.

Interest Expense - Interest expense increased $254,000, or 3.9 percent, in 2005 compared with 2004 primarily due to a $266,000 decrease in interest capitalized on conservation expenditures that are being recovered under the Company's 2003 Rate Plan. Once plant or regulatory assets begin to be recovered in the rates we collect, interest is no longer capitalized on those assets.

Interest expense decreased $551,000, or 7.8 percent, in 2004 compared with 2003 primarily due to scheduled redemptions of long-term debt in December 2003.

ENVIRONMENTAL MATTERS

The electric industry typically uses or generates a range of potentially hazardous products in its operations. We must meet various land, water, air and aesthetic requirements as administered by local, state and federal regulatory agencies. We believe that we are in substantial compliance with these requirements, and that there are no outstanding material complaints about our compliance with present environmental protection regulations.

The Company joined the Chicago Climate Exchange ("CCX"), a self-regulatory exchange that administers a market for reducing and trading greenhouse gas emission credits. We were the first utility in the northeast to join the CCX, and have committed voluntarily to reduce our emissions by 4 percent below our 1998 - 2001 baseline average by 2006, either directly or by purchasing credits. Participation in this program is not expected to significantly affect Company operating results. As part of our commitment to transparency in our environmental, social and economic activities, we published our first Corporate Responsibility Report in accordance with the Global Reporting Initiative guidelines. Investors can review the Company's 2004 Corporate Responsibility Report at www.greenmountainpower.biz, Who We Are, Environmental Policies.

Pine Street Barge Canal Superfund Site - In 1999, the Company entered into a United States District Court Consent Decree constituting a final settlement with the United States Environmental Protection Agency ("EPA"), the State of Vermont and numerous other parties of claims relating to a federal Superfund site in Burlington, Vermont, known as the "Pine Street Barge Canal." The consent decree resolves claims by the EPA for past site costs, natural resource damage claims and claims for past and future remediation costs. The consent decree also provides for the design and implementation of response actions at the site. In 2005, 2004 and 2003, the Company expended $0.6 million, $1.4 million and $2.6 million, respectively, to cover its obligations under the consent decree and we have estimated total future costs of the Company's future obligations under the consent decree to be $6.1 million. The estimated liability is not discounted, and it is possible that our estimate of future costs could change by a material amount. We have recorded a regulatory asset of $12.9 million to reflect unrecovered past and future Pine Street costs. Pursuant to the Company's 2003 Rate Plan, as approved by the VPSB, the Company began to amortize past unrecovered costs in 2005. The Company expects to amortize the full amount of incurred costs over 20 years without a return. If there were a substantial increase in Pine Street remediation costs, it could result in an adverse impact on earnings under our current earnings cap calculation.

RATES

During February 2006, the Company requested that the VPSB grant an accounting order to allow us to defer approximately $3.7 million in incremental hurricane-related power supply expenses to be incurred in the first quarter of 2006, and to also allow the Company to defer and amortize $1.3 million of incremental hurricane-related benefits realized in the fourth quarter of 2005 against these costs. The accounting order was approved by the VPSB in February 2006, allowing the Company to defer power supply expenses up to $2.4 million in the first quarter of 2006.

On December 22, 2003, the VPSB approved our 2003 Rate Plan, jointly proposed by the Company and the DPS. The 2003 Rate Plan covers the period from 2003 through 2006 and includes the following principal elements:

* The Company’s rates remained unchanged through 2004. The 2003 Rate Plan allows the Company to raise rates 1.9 percent, effective January 1, 2005, and an additional 0.9 percent, effective January 1, 2006. We submitted a cost of service schedule supporting the rate increases for 2005 and 2006 in accordance with the plan and the increases became effective on January 1, 2005 and January 1, 2006. The VPSB retains the discretion to open an investigation of the Company’s rates at any time, at the request of the DPS, the request of ratepayers, or on its own volition.

* The Company may seek additional rate increases or deferral of costs in extraordinary circumstances, such as severe storm repair costs, natural disasters, extended unanticipated unit outages, or significant losses of customer load.

* The Company’s allowed return on equity is capped at 10.5 percent for the period January 1, 2003 through December 31, 2006. Certain exclusions, commonly made in setting rates, make it unlikely that the Company will achieve its allowed return on equity for its core utility operations. Excess earnings in 2005 or 2006 will be refunded to customers as a credit on customer bills or applied to reduce regulatory assets, as the Department directs.

* The Company carried forward into 2004 $3.0 million in deferred revenue remaining at December 31, 2003, from the Company’s 2001 Settlement Order (summarized below). These revenues were applied in 2004 to offset increased costs.

* The Company began amortizing (recovering), in January 2005, certain regulatory assets, including Pine Street Barge Canal environmental site costs and past demand-side management program costs, with those amortizations to be allowed in future rates. Pine Street costs will be recovered over a twenty-year period without a return.

    * The Company and the Department have agreed to work cooperatively to develop and propose an alternative regulation plan as authorized by legislation enacted in Vermont in 2003.

In January 2001, the VPSB issued the 2001 Settlement Order, which included the following:

* Rates were set at levels that recover the Company’s VJO Contract costs, effectively ending the regulatory disallowances experienced by the Company from 1998 through 2000;

* The Company and customers shall share equally any premium above book value realized by the Company in any future merger, acquisition or asset sale, subject to an $8.0 million limit on the customers' share, adjusted for inflation; and

* The Company's further investment in non-utility operations was restricted until new rates went into effect, which occurred in January 2005. Although this restriction has expired, we have no plans to make material investments in non-utility operations.

LIQUIDITY AND CAPITAL RESOURCES

Our cash, net working capital and net operating cash flows are as follows:

	At December 31, 2005		2004	
(In thousands)				
Cash and cash equivalents	$	6,500	$	1,720
Current assets	$	64,312	$	44,809
Less current liabilities		63,156		33,815
Net working capital	$	1,156	$	10,994
Net cash provided by operating activities	$	29,770	$	23,916

Cash and cash equivalents increased by approximately $4.8 million in 2005. Operating cash flows increased by $5.9 million from the prior year as a result of a 2005 retail rate increase that replaced deferred revenue recognition in 2004, increases in depreciation and amortization, and an increase in taxes payable arising primarily from stronger than expected fourth quarter results. Net cash used in investing activities totaled $18.0 million, principally for investments to construct utility plant.

We expect most of our utility construction expenditures and dividends to be financed by net cash provided by operating activities. We expect to finance our increasing investment in VELCO through debt issuance. We anticipate that we will issue long-term debt of approximately $25 million in 2006 for scheduled first mortgage bond redemptions of $14 million and to refinance accumulated short-term debt arising from investments in VELCO. Material risks to cash flow from operations include regulatory risk, power supply risks, slower than anticipated load growth and unfavorable economic conditions.

Construction and Investments - Our capital requirements result from the need to construct facilities or to invest in programs to meet anticipated customer demand for electric service. The Company plans to invest approximately $25 million in VELCO through 2008, assuming that VELCO maintains a capital structure of 75 percent debt and 25 percent equity, including $16 million of planned investment during 2006. Our planned investments will fund an increase in the amount of equity in VELCO’s capital structure and increased transmission investment, principally driven by construction of the Northwest Reliability Project and other Vermont construction projects.

Future capital expenditures are expected to approximate $20 - 24 million annually. Expected reductions in Pine Street remediation costs should be offset by increased generation expenditures. Capital expenditures over the past three years and forecasted for 2006 are as follows:

		Generation		Transmission		Distribution		Other*		Total
(In thousands)										
Actual:										
2003	$	2,629	$	1,496	$	6,538	$	6,622	$	17,285
2004		3,053		2,898		8,662		5,005	$	19,618
2005	$	2,060	$	596	$	8,541	$	6,400	$	17,597
Forecast:										
2006	$	5,096	$	1,835	$	10,662	$	6,079	$	23,672

* Other includes Pine Street Barge Canal net expenditures of $2.6 million in 2003, $1.4 million in 2004, $0.6 million in 2005, and an estimated $1.1 million in 2006.

Dividend Policy - The Company expects to increase the annual dividend on its common stock in the first quarter of each year until the payout ratio falls in the middle of a payout range of between 50 percent and 70 percent of anticipated earnings, so long as financial and operating results permit. We believe this payout ratio to be consistent with that of other electric utilities having similar risk profiles. Our recent dividend history is as follows:

Period Reflecting Dividend Change	New Annual Dividend Rate	Annual Payout Ratio
2006 1st Quarter	1.12	n/a
2005 1st Quarter	1.00	48%
2004 1st Quarter	.88	42%
2002 4th Quarter	.76	39%

Payout ratio computed as annual dividend rate divided by annual earnings from continuing operations.

FINANCING AND CAPITALIZATION
During June 2005, the Company negotiated a 364-day revolving credit agreement (the "Fleet-Sovereign Agreement") with Fleet Financial Services ("Fleet") joined by Sovereign Bank. The Fleet-Sovereign Agreement is for $30.0 million, unsecured, and allows the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. There was no short-term debt outstanding on the Fleet-Sovereign Agreement at December 31, 2005. There was $3.0 million outstanding on the Fleet-Sovereign Agreement at December 31, 2004 at an average rate of 5.25 percent. There was no non-utility short-term debt outstanding at December 31, 2005 or 2004. The Fleet-Sovereign Agreement expires June 14, 2006. The Company anticipates that it will secure financing that replaces some or all of its expiring facilities during 2006. We expect to increase the term of the revolving credit facility to between three and five years (subject to VPSB approval) during 2006.

The credit ratings of the Company's first mortgage bonds at December 31, 2005 were:

	Moody's	Standard & Poor's
First mortgage bonds	Baa1	BBB

PERFORMANCE ASSURANCE
The Company is subject to performance assurance requirements associated with its power purchase and sale transactions through ISO-NE under the Financial Assurance Policy for NEPOOL members. While the Company is generally a net seller to ISO-NE, it must post collateral if the net amount owed exceeds its credit limit at ISO-NE. A company’s credit limit is calculated as a percentage, based on its credit rating, of its net worth. The Company’s present credit limit with ISO-NE is approximately $1.5 million. ISO-NE reviews collateral requirements on a daily basis. As of December 31, 2005, the Company had no collateral requirements with ISO-NE.

The Company is also subject to performance assurance requirements under the VYNPC Contract to purchase power from Vermont Yankee. If ENVY, the seller, has commercially reasonable grounds for insecurity regarding the Company’s ability to pay for its monthly purchases, ENVY may ask VYNPC and VYNPC may then ask the Company to provide adequate financial assurance payment. The Company has never been requested to post collateral under this contract.

In the event of a change in the Company's first mortgage bond credit rating to below investment grade, scheduled payments under the Company's first mortgage bonds would not be affected. Such a change would require the Company to post what would currently amount to a $4.3 million bond under our remediation agreement with the EPA regarding the Pine Street Barge Canal site. The Morgan Stanley Contract requires credit assurances if the Company's first mortgage bond credit ratings are lowered to below investment grade by either of the credit rating agencies listed above. The Company typically utilizes EEI standard contracts for residual power supply contractual arrangements that contain triggers that require posting of letters of credit or other credit assurances if amounts due the creditor party exceed certain thresholds, frequently tied to the Company’s credit rating. While the Company’s principal long-term contracts do not contain these strict provisions, if replacement contracts were entered into today, they likely would contain specified collateral thresholds and credit rating triggers. We do not expect additional material amounts of expense from these terms.

The following table presents a summary of certain material contractual obligations and other expected payments existing as of December 31, 2005.

Payments Due by Period

At December 31, 2005	**Total**	**2006**	**2007 and 2008**	**2009 and 2010**	**After 2011**

(In thousands)					
Long-term debt	$ 93,000	$ 14,000	$ -	$ -	$ 79,000
Interest on long-term debt	63,636	6,534	11,068	11,068	34,966
Capital lease obligations	3,943	475	771	771	1,927
Hydro-Quebec power supply contracts	519,192	51,596	103,020	103,993	260,583
Morgan Stanley Contract	10,160	10,160	-	-	-
Independent Power Producers	152,523	16,642	33,285	33,285	69,312
Stony Brook contract	26,499	1,866	3,480	3,541	17,612
VYNPC PPA	210,687	33,595	64,144	69,811	43,137
Benefit plan contributions*	20,000	2,000	4,000	4,000	10,000
VELCO capital contributions	25,230	15,660	9,570	-	-
Total	$ 1,124,870	$ 152,528	$ 229,338	$ 226,467	$ 516,537

See the captions "Power Supply Expense" and "Power Contract Commitments" for additional information
about the Hydro-Quebec and Morgan Stanley power supply contracts
*Benefit plan contributions are
estimated through 2015

Off-Balance Sheet Arrangements and Other Contractual Obligations - The Company does not use off-balance sheet financing arrangements, such as securitization of receivables or obtaining access to assets through special purpose entities. We have material power supply commitments that are discussed in detail under the captions "Power Contract Commitments" and "Power Supply Expenses." We own an equity interest in VELCO, which requires the Company to pay a portion of VELCO’s operating costs, including its debt service costs. We also own an equity interest in VYNPC in which we are obligated to pay a portion of VYNPC’s operating costs based on our Vermont entitlement percentage.

Other Risks - In 2002, the owners of property along the shoreline of Joe's Pond, an impoundment located in Danville, Vermont, created by the Company's West Danville hydroelectric generating facility, filed an inquiry with the VPSB seeking review of certain dam improvements made by the Company in 1995, alleging that the Company did not obtain all necessary regulatory approvals for the 1995 improvements and that the Company's improvements and subsequent operation of the dam have caused flooding of the shoreline and property damage. The Company received VPSB approval for, and has made additional dam improvements, at the facility. The Company and the Department stipulated to a penalty of $50,000 on the matter. The VPSB approved the stipulation in July 2005 and the penalty has been paid. In addition, numerous owners of shoreline property on Joe’s Pond have filed a lawsuit in Vermont superior court seeking damages for property damage allegedly caused by the Company’s negligent conduct in operating and maintaining the dam. The Company does not expect the litigation to result in a material adverse effect on its operating results or financial condition.

Effects of Inflation - Financial statements are prepared in accordance with generally accepted accounting principles and report operating results in terms of historic costs. This accounting provides reasonable financial statements but does not always take inflation into consideration. As rate recovery is based on these historical costs and known and measurable changes, the Company is able to receive some rate relief for inflation. It does not receive immediate rate recovery relating to fixed costs associated with Company assets. Such fixed costs are recovered based on historic figures.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

GREEN MOUNTAIN POWER CORPORATION
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES

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

GREEN MOUNTAIN POWER CORPORATION
Consolidated Statements of Income

	For the Years Ended December 31		
	2005	**2004**	**2003**
(In thousands, except per share data)			
Revenues			
Retail and other revenues	$ 217,562	$ 207,922	$ 201,569
Wholesale revenues	28,298	22,652	78,901
Total operating revenues	245,860	230,574	280,470
Operating expenses-Power Supply:			
Purchases from others	143,512	137,503	189,450
Company-owned generation	6,477	6,516	7,856
Other operating	24,751	19,295	17,534
Transmission	16,453	15,656	14,783
Maintenance	11,247	9,746	9,721
Depreciation and amortization	15,074	13,931	13,803
Taxes other than income	6,589	6,687	6,897
Income taxes	5,676	5,762	5,120
Total operating expenses	229,779	215,096	265,164
Operating income	16,081	15,478	15,306
Other income			
Equity in earnings of affiliates and non-utility operations	1,585	1,232	1,493
Allowance for equity funds used during construction	29	449	387
Other income	268	714	409
Other deductions	(157)	(308)	(210)
Total other income	1,725	2,087	2,079
Interest charges			
Long-term debt	6,534	6,534	7,021
Other	244	257	303
Allowance for borrowed funds used during construction	(18)	(285)	(267)
Total interest charges	6,760	6,506	7,057
Income from continuing operations before preferred dividends	11,046	11,059	10,328
Dividends on preferred stock	-	-	3
Income from continuing operations	11,046	11,059	10,325
Income from discontinued operations, net	134	525	79
Net income applicable to common stock	$ 11,180	$ 11,584	$ 10,404
Earnings per share			
Basic earnings per share-continuing operations	$ 2.12	$ 2.18	$ 2.08
Basic earnings per share-discontinued operations	0.03	0.10	0.01
Basic earnings per share	$ 2.15	$ 2.28	$ 2.09
Diluted earnings per share-continuing operations	$ 2.09	$ 2.10	$ 2.01

Diluted earnings per share-discontinued operations		0.03		0.10		0.01
Diluted earnings per share	$	2.12	$	2.20	$	2.02
Cash dividends declared per share	$	1.00	$	0.88	$	0.76
Weighted average common shares outstanding-basic		5,195		5,083		4,980
Weighted average common shares outstanding-diluted		5,284		5,254		5,140

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

GREEN MOUNTAIN POWER CORPORATION
Consolidated Statements of Cash Flows

	For the Years Ended December 31		
	2005	**2004**	**2003**
Operating Activities:		(in thousands)	
Income from continuing operations before preferred dividends	$ 11,046	$ 11,059	$ 10,328
Adjustments to reconcile net income to net cash			
provided by operating activities:			
Depreciation and amortization	15,074	13,931	13,803
Dividends from associated companies	1,273	863	2,081
Equity in undistributed earnings of associated companies	(1,318)	(880)	(1,197)
Allowance for funds used during construction	(47)	(733)	(654)
Amortization of deferred purchased power costs	2,581	318	318
Deferred income tax expense, net of investment tax credit amortization	(2,563)	3,699	1,479
Deferred purchased power costs	(2,023)	(667)	(570)
Deferred regulatory earnings	2,778	(2,970)	(1,121)
Environmental and conservation deferrals, net	(312)	(1,041)	(1,890)
Gain on sale of property	-	(402)	-
Share-based compensation	1,354	1,244	-
Changes in:			
Accounts receivable and accrued utility revenues	(1,705)	(1,120)	(189)
Prepayments, fuel and other current assets	(950)	(418)	(1,188)
Accounts payable and other current liabilities	470	1,567	(676)
Accrued income taxes payable and receivable	6,031	(2,069)	(340)
Other	(2,255)	1,010	(415)
Net cash provided by continuing operations	29,434	23,391	19,769
Operating cash flows from discontinued operations	337	525	79
Net cash provided by operating activities	29,770	23,916	19,848
Investing Activities:			
Construction expenditures	(16,978)	(18,577)	(15,395)
Restriction of cash for renewable energy investments	(973)	(354)	-
Proceeds from sale of property	-	648	-
Investment in associated companies	-	(4,579)	(108)
Return of capital from associated companies	189	314	7,615
Investment in nonutility property	(210)	(338)	(198)
Net cash used in investing activities	(17,972)	(22,886)	(8,086)

Financing Activities:						
Repurchase of preferred stock		-		-		(85)
Payments to acquire treasury stock		-		-		(3)
Payments on capital lease		(187)		-		-
Issuance of common stock		1,373		1,885		995
Reduction in long-term debt and term loan		-		-		(8,000)
Short-term debt		(3,000)		2,500		(2,000)
Cash dividends		(5,205)		(4,481)		(3,792)
Net cash used in financing activities		(7,019)		(96)		(12,885)
Net increase in cash and cash equivalents		4,780		934		(1,123)
Cash and cash equivalents at beginning of period		1,720		786		1,909
Cash and cash equivalents at end of period	$	6,500	$	1,720	$	786
Supplemental Disclosure of Cash Flow Information:						
Cash paid year-to-date for:						
Interest	$	6,700	$	6,691	$	7,120
Income taxes		2,221		3,043		2,915
Non-cash construction additions		1,229		1,563		1,433

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

GREEN MOUNTAIN POWER CORPORATION
Consolidated Balance Sheets

	At December 31, 2005	2004
ASSETS	In thousands	
Utility plant		
Utility plant, at original cost	$ 347,947	$ 339,269
Less accumulated depreciation	122,924	119,633
Utility plant, net of accumulated depreciation	225,023	219,636
Property under capital lease	4,369	4,731
Construction work in progress	7,519	8,345
Total utility plant, net	236,911	232,712
Other investments		
Associated companies, at equity	10,036	10,179
Other investments	10,627	8,780
Total other investments	20,663	18,959
Current assets		
Cash and cash equivalents	6,500	1,720
Accounts receivable, less allowance for doubtful accounts of $484 and $620	19,594	18,216
Accrued utility revenues	7,291	6,964
Fuel, materials and supplies, average cost	6,360	4,848
Power supply derivative asset	15,342	6,553
Power supply regulatory asset	7,791	2,794
Prepayments and other current assets	1,434	1,997
Income tax receivable	-	1,717
Total current assets	64,312	44,809
Deferred charges		
Demand side management programs	5,835	7,293
Purchased power costs	1,812	2,322
Pine Street Barge Canal	12,861	13,250
Power supply regulatory asset	22,344	20,027
Power supply derivative asset	-	4,183
Other regulatory assets	5,809	6,932
Other deferred charges	3,068	1,113
Total deferred charges	51,729	55,120
Non-utility		
Property and equipment	246	247
Other assets	407	508
Total non-utility assets	653	755
Total assets	$ 374,268	$ 352,355

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

GREEN MOUNTAIN POWER CORPORATION
Consolidated Balance Sheets

	At December 31,	
	2005	**2004**
CAPITALIZATION AND LIABILITIES	In thousands except share data	
Capitalization		
Common stock, $3.33 1/3 par value, authorized 10,000,000 shares (issued 6,060,962 and 5,968,118)	$ 20,203	$ 19,894
Additional paid-in capital	81,271	78,852
Retained earnings	35,864	29,889
Accumulated other comprehensive income	(3,263)	(2,353)
Treasury stock, at cost (827,639 shares)	(16,701)	(16,701)
Total common stock equity	117,374	109,581
Long-term debt, less current maturities	79,000	93,000
Total capitalization	196,374	202,581
Capital lease obligation	3,944	4,493
Current liabilities		
Current portion of long term debt	14,000	-
Short-term debt	-	3,000
Accounts payable, trade and accrued liabilities	14,196	9,437
Accounts payable to associated companies	1,483	7,391
Accrued taxes	5,603	1,290
Power supply derivative liability	7,791	2,794
Power supply regulatory liability	15,342	6,553
Customer deposits	1,052	1,063
Interest accrued	1,137	1,136
Other	2,552	1,151
Total current liabilities	63,156	33,815
Deferred credits		
Power supply derivative liability	22,344	20,027
Power supply regulatory liability	-	4,183
Accumulated deferred income taxes	28,092	32,223
Unamortized investment tax credits	2,280	2,564
Pine Street Barge Canal cleanup liability	6,096	6,458
Accumulated cost of removal	21,105	19,806
Deferred compensation	8,213	8,872
Other regulatory liabilities	6,513	4,012
Other deferred liabilities	13,777	11,150
Total deferred credits	108,420	109,295
COMMITMENTS AND CONTINGENCIES, Note 3		
Non-utility		
Net liabilities of discontinued segment	2,374	2,171
Total non-utility liabilities	2,374	2,171
Total capitalization and liabilities	$ 374,268	$ 352,355

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

Consolidated Statements of Changes in Stockholders' Equity and Comprehensive Income

	Common Stock Shares	Common Stock Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income	Treasury Stock	Total Common Equity
(In thousands except share data)							
BALANCE, December 31, 2002	**4,954,857**	**$ 19,276**	**$ 75,347**	**$ 16,171**	**$ (2,374)**	**$ (16,698)**	**$ 91,722**
Common stock issuance:							
Stock options and grants	78,358	260	734	-	-	-	994
Common stock repurchase	-	-	-	-	-	(3)	(3)
Income before preferred dividends	-	-	-	10,407	-	-	10,407
Other comprehensive income	-	-	-	-	587	-	587
Common stock dividends-$0.76 per share	-	-	-	(3,789)	-	-	(3,789)
Preferred stock dividends	-	-	-	(3)	-	-	(3)
BALANCE, December 31, 2003	**5,033,215**	**19,536**	**76,081**	**22,786**	**(1,787)**	**(16,701)**	**99,915**
Common stock issuance:							
Stock options and grants	107,264	358	2,771	-	-	-	3,129
Net income	-	-	-	11,584	-	-	11,584
Other comprehensive loss	-	-	-	-	(566)	-	(566)
Common stock dividends-$0.88 per share	-	-	-	(4,481)	-	-	(4,481)
BALANCE, December 31, 2004	**5,140,479**	**19,894**	**78,852**	**29,889**	**(2,353)**	**(16,701)**	**109,581**
Common stock issuance:							
Stock options and grants	92,844	309	2,419	-	-	-	2,728
Net income	-	-	-	$ 11,180	-	-	11,180
Other comprehensive loss	-	-	-	-	(910)	-	(910)
Common stock dividends-$1.00 per	-	-	-	(5,205)	-	-	(5,205)

share							
BALANCE, December 31, 2005	**5,233,323**	**$ 20,203**	**$ 81,271**	**$ 35,864**	**$ (3,263)**	**$ (16,701)**	**$ 117,374**

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

Consolidated Statements of Comprehensive Income	**For the years ended December 31,**		
	2005	**2004**	**2003**
In thousands			
Net income	$ 11,180	$ 11,584	$ 10,404
Minimum pension liability adjustment, net of applicable income taxes	(910)	(566)	587
of $620 benefit, $391 benefit and $400 expense, respectively			
Other comprehensive income	$ 10,270	$ 11,018	$ 10,991

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

Notes to Consolidated Financial Statements

A. SIGNIFICANT ACCOUNTING POLICIES

Organization and Basis of Presentation. Green Mountain Power Corporation (the "Company") is an investor-owned electric utility that transmits, distributes and sells electricity and utility construction services in Vermont with a principal service territory that includes approximately one quarter of Vermont's population. Most of the Company’s net income is generated from retail sales in its regulated electric utility operation, which purchases and generates electric power and distributes electricity to approximately 90,000 customer accounts. The Company's subsidiary, Green Mountain Power Investment Company ("GMPIC"), was created in December 2002 to hold the Company’s investment in Vermont Yankee Nuclear Power Corporation ("Vermont Yankee" or "VYNPC").

The Company’s remaining active wholly-owned subsidiary, which is not regulated by the Vermont Public Service Board ("VPSB" or the "Board"), is GMP Real Estate Corporation. The results of GMP Real Estate Corporation and the Company’s unregulated rental water heater program are included in earnings of affiliates and non-utility operations in the Other Income section of the Consolidated Statements of Income. Summarized financial information for GMP Real Estate Corporation and the Company's unregulated water heater program is as follows:

For the Years ended December 31,						
In thousands		2005		2004		2003
Revenue	$	941	$	961	$	1,087
Expense		652		594		704
Net Income	$	289	$	367	$	253

The Company accounts for its investments in VYNPC, Vermont Electric Power Company, Inc. ("VELCO"), New England Hydro-Transmission Corporation, and New England Hydro-Transmission Electric Company using the equity method of accounting. The Company's share of the net earnings or losses of these companies is also included in the Other Income section of the Consolidated Statements of Income. See Note B for additional information.

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.

Use of Estimates. In preparing the financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's financial statements, particularly as they relate to unbilled revenue, pension expense and contingencies. However, the Company believes it has taken reasonable positions, where assumptions and estimates are used, in order to minimize the impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of unbilled and deferred revenue, pension and postretirement plan assumptions, contingency reserves, accumulated removal obligations, regulatory assets and liabilities, the allowance for uncollectible accounts receivable and derivative valuation.

Regulatory Accounting. The Company's utility operations, including accounting records, rates, operations and certain other practices of its electric utility business, are subject to the regulatory authority of the Federal Energy Regulatory Commission ("FERC") and the VPSB.

The Company's operating results are subject to an earnings cap equal to its allowed rate of return on equity of 10.5 percent on investments allowed to be recovered by the VPSB, reduced by amounts normally excluded for purposes of setting rates. Nearly all of the Company's continuing operations are treated for ratemaking purposes as regulated operations. The Company's 2005 return on equity was 9.85 percent reflecting the exclusions mentioned above. These exclusions also make it unlikely that the Company's operating results will achieve its allowed rate of return while its earnings are subject to the earnings cap.

The accompanying consolidated financial statements conform to accounting principles generally accepted in the United States of America applicable to rate-regulated enterprises in accordance with Statement of Financial Accounting Standards No. ("SFAS") 71 ("SFAS 71"), "Accounting for Certain Types of Regulation." Under SFAS 71, the Company accounts 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. Incurred costs are deferred as regulatory assets when the Company concludes that future revenue will be provided to permit recovery of the previously incurred cost. The Company analyzes evidence supporting deferral, including provisions for recovery in regulatory orders, past regulatory precedent, other regulatory correspondence and legal representations.

Conditions that could give rise to the discontinuance of SFAS 71 include increasing competition that restricts the Company's ability to recover specific costs, and a change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. In the event that the Company no longer meets the criteria under SFAS 71, the Company would be required to write off related regulatory assets, net of regulatory liabilities as summarized in the following table:

Regulatory assets and liabilities

	At December 31, 2005		At December 31, 2004	
Regulatory assets:	(in thousands)			
Demand-side management programs	$	5,835	$	7,293
Purchased power costs		1,812		2,322
Pine Street barge canal		12,861		13,250
Power supply regulatory assets		30,135		22,821
Other regulatory assets		5,809		6,932
Total regulatory assets*		56,452		52,618
Regulatory liabilities:				
Accumulated cost of removal		21,105		19,806
Power supply regulatory liability		15,342		10,736
Other regulatory liabilities		6,513		4,012
Total regulatory liabilities		42,960		34,554
Regulatory assets net of regulatory liabilities	$	13,492	$	18,064

**Substantially all regulatory assets are being recovered in current rates effective January 1, 2005 and, with the exception of Pine Street Barge Canal and certain power contract related costs, include an associated return on investment.*

The power supply regulatory assets and liabilities represent the value of certain power supply contracts that must be marked to fair value as derivatives under current accounting rules. The Company records contract specified prices for electricity as expense in the period used, as opposed to fair market values reflected in the above table. The power supply contract expenses are fully recovered in the rates we charge, and are discussed in detail under Power Supply Derivatives.

The Company defers and amortizes replacement power costs associated with significant unscheduled outages at the Vermont Yankee nuclear power plant owned by Entergy Nuclear Vermont Yankee LLC ("ENVY') and other extraordinary losses. The Company also defers and amortizes extraordinary costs associated with natural disaster, severe storms costs or significant loss of load under the Company’s current rate plan. The Company recovers these costs from customers over periods determined by the VPSB in a future rate filing.

Other regulatory assets totaled $5.8 million and $6.9 million at December 31, 2005 and 2004, respectively, and consist of regulatory deferrals of storm damages, rights-of-way maintenance, other employee benefits, preliminary survey and investigation charges, transmission interconnection charges, regulatory tax assets and various other projects and deferrals. Most of these assets are amortized over a period of between five and seven years.

Other regulatory liabilities consist of earnings above the earnings cap, amounts received from VYNPC that were subject to a regulatory deferral order and regulatory tax liabilities.

The Company continues to believe, based on current regulatory circumstances, that the use of regulatory accounting under SFAS 71 remains appropriate and that its regulatory assets are probable of recovery. The Company provides for regulatory disallowances when management believes it is both probable and estimable that a regulatory liability exists.

Accumulated costs of removal represent asset retirement costs previously recovered from ratepayers for other than legal obligations. In accordance with SFAS 143, "Accounting for Asset Retirement Obligations," the Company reflects these amounts as a regulatory liability. Prior to SFAS 143, these amounts were recorded as a part of the Company's Accumulated Depreciation. We expect, over time, to recover or settle through future revenues any under- or over-collected net cost of removal.

Discontinued Operations. The Company accounts for its wholly-owned subsidiary, Northern Water Resources ("NWR") as a discontinued operation. NWR's assets and liabilities consist primarily of deferred tax assets and liabilities relating to a number of investments that the company has discontinued, inactivated, sold in part or retains as passive minority interests. Remaining holdings include a minority equity investment in a wind project that usually, but not always, generates tax losses; minority interest in a manufacturer of waste treatment equipment; and non-performing loans. The Company recognized income of $.03 per share from Discontinued Operations during 2005 primarily as a result of adjustments to tax valuation allowances arising from the realization of tax capital gains, compared with earnings of $.10 and $.01 in 2004 and 2003, respectively. Income in 2004 reflects diminished exposure to outstanding litigation that led to reversal of previously recorded reserves. Substantially all of NWR's investments have been written off except for associated deferred tax amounts, net of applicable valuation allowances.

Impairment. The Company is required to evaluate long-lived assets, including regulatory assets, for potential impairment. Assets that are no longer probable of recovery through future cash flows would be re-valued based upon future cash flows. Regulatory assets are charged to expense in the period in which they are no longer probable of future recovery. As of December 31, 2005, based upon management's analysis of the regulatory environment within which the Company currently operates, the Company does not believe that an impairment loss should be recorded. Competitive influences or regulatory developments may impact this status in the future.

Utility Plant. The cost of plant additions is recorded at original cost and includes all construction-related direct labor and materials, as well as indirect construction costs. The cost of plant additions includes the cost of money ("Allowance for Funds Used During Construction" or "AFUDC") when costs applicable to construction work in progress have not otherwise been provided a return through regulatory proceedings. The costs of renewals and improvements of property units are capitalized. The costs of maintenance, repairs and replacements of minor property items are charged to maintenance expense. The costs of units of property removed from service, net of salvage value, are charged to accumulated depreciation. The following table summarizes the Company’s investments in utility plant.

Property Summary at December 31,	Approximate Average depreciable life in years		2005		2004
			In thousands		
Property, Plant and Equipment:					
Intangible, FERC Licenses and Software	13	$	11,162	$	12,390
Generation	41		73,413		72,156
Transmission	39		40,311		39,368
Distribution	37		193,261		186,863
General, including transportation	18		29,800		28,492
Total Plant in Service			347,947		339,269
Accumulated Depreciation and Amortization			(122,924)		(119,633)
Net Plant in Service			225,023		219,636
Capital Lease			4,369		4,731
Construction Work in Progress			7,519		8,345
Total Utility Plant, net		$	236,911	$	232,712

Depreciation and Amortization. The Company provides for depreciation using the straight-line method based on the cost and estimated remaining service life of the depreciable property outstanding at the beginning of the year and adjusted for salvage value and cost of removal of the property.

The annual depreciation provision was approximately 3.4 percent during 2005, 3.3 percent during 2004 and 3.3 percent during 2003 of total depreciable property.

The Company amortizes nearly all of its intangible and regulatory assets using the straight-line method based on the cost and amortization period approved by the VPSB for the intangible property outstanding at the beginning of the year. Amortization expense totaled $3.8 million, $3.3 million and $3.5 million for 2005, 2004 and 2003, respectively.

Disposal of Assets. During 2004, the Company sold non-utility property consisting of land and buildings for $648,000. The Company recognized a gain of approximately $402,000 related to the sale of these assets, which is recorded in Other Income in the Consolidated Statement of Income.

Cash and Cash Equivalents. Cash and cash equivalents include short-term investments with original maturities less than ninety days.

Restricted Cash. The Company has set aside $1,327,000, included in Other Investments, as of December 31, 2005, for renewable generation development under a VPSB regulatory order.

Operating Revenues. Operating revenues consist principally of retail sales of electricity at regulated rates. Revenue is recognized when electricity is delivered. The Company accrues utility revenues, based on estimates of electric service rendered and not billed at the end of an accounting period, in order to match revenues with related costs. Wholesale revenues represent sales of electricity to other utilities, typically for resale, and to ISO New England for amounts by which our power supply resources exceed customer loads. The Company recognizes deferred revenues, when required to achieve its allowed rate of return, under a VPSB order issued in 2001, and extended through 2004 under a subsequent VPSB order. The Company also recognizes deferred revenue when its earnings exceed its earnings cap. The Company deferred $1.9 million of operating revenue during 2005 and recognized $3.0 million and $1.1 million in deferred revenues during 2004 and 2003, respectively. See Note H for additional information.

Allowance for Doubtful Accounts. The Company estimates the amount of accounts receivable that will not be collected and records these amounts as a reduction to accounts receivable.

Allowance for Doubtful Accounts	Balance at Beginning of Period	Additions Charged to Cost & Expenses	Accounts Charged Off	Balance at End of Period
In thousands				
2005	$ 620	$ 308	$ 444	$ 484
2004	691	549	620	620
2003	547	750	606	691

Earnings Per Share. Basic earnings per share ("EPS") is calculated by dividing net income 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 are 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, including stock options.

Stock-Based Compensation

During the year ended December 31, 2000, the Company granted options for 335,300 shares under its 2000 Stock Plan exercisable over vesting schedules of between one and four years. During 2003, 2002 and 2001, the Company granted additional options of 4,000, 80,300 and 56,450, respectively. SFAS 123 requires disclosure of pro-forma information regarding net income and earnings per share. The Company adopted the prospective method of accounting for stock-based compensation under SFAS 148, *Accounting for Stock-Based Compensation* beginning January 1, 2003. The information presented below has been determined as if the Company accounted for all past employee and director stock options under the fair value method of that statement.

Pro-forma net income	For the years ended December 31,		
	2005	2004	2003
In thousands, except per share amounts			
Net income reported	$ 11,180	$ 11,584	$ 10,404
Pro-forma net income	$ 11,180	$ 11,503	$ 10,242
Net income per share			
As reported-basic	$ 2.15	$ 2.28	$ 2.09
Pro-forma basic	$ 2.15	$ 2.26	$ 2.06
As reported-diluted	$ 2.12	$ 2.20	$ 2.02
Pro-forma diluted	$ 2.12	$ 2.19	$ 1.99
Stock compensation included in results, net of tax	$ 806	$ 740	$ 253
Fair value of all stock compensation	806	821	414

Major Customers and Other Concentration Risks. The Company has one major retail customer, International Business Machines Corporation ("IBM"), that accounted for 23.5 percent, 24.1 percent and 24.1 percent of retail MWh sales, and 15.3 percent, 16.2 percent and 16.6 percent of the Company's retail operating revenues in 2005, 2004 and 2003, respectively.

We currently estimate that a hypothetical shutdown of the IBM facility would not necessitate a retail rate increase for all remaining customers, including secondary and tertiary impacts of such a shutdown on other customer sales, because the Company could sell contracted power supply resources into the wholesale market at prices in excess of current rates charged to IBM.

Our material power supply contracts are principally with Hydro Quebec and VYNPC. These contracts are expected to meet approximately 75 percent of our anticipated annual demand requirements during the next five years. 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. We also have a power supply contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract") for approximately 17 percent of our annual load that expires December 31, 2006.

Fair Value of Financial Instruments. The fair value and carrying value of the Company's first mortgage bonds and derivative contracts is summarized in the following table:

Fair Value of Financial Instruments				
	At December 31,			
	2005		2004	
In thousands	Calculated Fair Value	Amount carried on balance sheet	Calculated Fair Value	Amount carried on balance sheet
Long-Term Debt, net,(Note F)	$ 76,851	$ 79,000	$ 91,274	$ 93,000
Derivatives, net	14,793	14,793	12,085	12,085
Current portion of long-term debt	14,080	14,000	-	-

The book value of accounts receivable, accrued utility revenues, other investments, cash surrender value of life insurance, short-term debt, accounts payable, customer deposits and accrued interest approximate fair value due to their short-term, highly liquid nature.

The fair value of derivatives is discussed below under "Derivative Instruments."

Environmental Liabilities. The Company is subject to federal, state and local regulations addressing air and water quality, hazardous and solid waste management and other environmental matters. Only those site investigation, characterization and remediation costs currently known and determinable can be considered "probable and reasonably estimable" under SFAS 5, *Accounting for Contingencies.* As costs become probable and reasonably estimable, reserves are adjusted as appropriate. As reserves are recorded, regulatory assets are recorded to the extent environmental expenditures are expected to be recovered in rates. Estimates are based on studies provided by third parties.

Purchased Power. The Company records the annual cost of power obtained under long-term executory contracts as operating expenses. The contracts do not convey to the Company the right to use the related property plant, or equipment.

Derivative Instruments. The Company utilizes derivative instruments primarily to reduce power supply risk. The Company does not hold derivative trading positions. The Company has continued to record expense related to derivatives in the period settled consistent with an accounting order issued by the VPSB.

SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, established accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS 133 requires that changes in the derivative’s fair value be recognized currently in earnings unless specific hedge accounting criteria are met.

On April 11, 2001, the VPSB issued an accounting order that requires the Company to defer recognition of any earnings or other comprehensive income effects relating to future periods caused by the application of SFAS 133 to power supply arrangements that qualify as derivatives.

The Morgan Stanley Contract is used to hedge against increases in fossil fuel prices. Morgan Stanley purchases a portion of the Company's power supply resources at index (fossil fuel resources) or specified (i.e., contracted resources) prices and then sells to us at a fixed rate to serve pre-established load requirements. This contract allows management to fix the cost of much of its power supply requirements, subject to power resource availability and other risks. The Morgan Stanley Contract expires December 31, 2006.

We currently have an agreement (the "9701 agreement") that grants Hydro Quebec an option to call power at prices below current and estimated future market rates. This agreement is effective through 2015. From time to time, we use forward contracts to hedge the 9701 agreement. Since we are required under a VPSB order to defer recognition of any SFAS 133 earnings effect until settled, we do not evaluate derivatives for hedge accounting treatment. If the Company were to terminate or sell any of its derivative contracts, it would immediately record the gain or loss on that contract, absent a regulatory order to do otherwise.

The table below presents assumptions used to estimate the fair value of the Morgan Stanley Contract, the 9701 agreement and forward sales contracts. The forward prices for electricity used in this analysis are consistent with the Company’s current long-term wholesale energy price forecast.

	Option Value Model	Risk Free Interest Rate	Price Volatility	Average Forward Price	Contract Expires
Morgan Stanley Contract	Deterministic	4.4%	42%	$ 97	2006
9701 agreement	Black-Scholes	4.4%	29%-10%	$ 69	2015
Forward sale contracts	Deterministic	n/a	0%	$ 96	2006

At December 31, 2005, the Company had a power supply derivative liability of $30.1 million reflecting the fair value of the 9701 agreement, and a power supply derivative asset of $15.3 million, reflecting the $15.1 million fair value of the Morgan Stanley Contract and the remaining asset attributable to the forward sale contracts. Corresponding regulatory assets and regulatory liabilities total $30.1 million and $15.3 million, respectively. Amounts due during 2006 are classified in current assets and current liabilities.

At December 31, 2004, the Company had a power supply derivative liability of $22.8 million reflecting the fair value of the 9701 agreement, and a power supply derivative asset of $10.7 million, reflecting the fair value of the Morgan Stanley Contract. Corresponding regulatory assets and regulatory liabilities total $22.8 million and $10.7 million, respectively. Amounts due during 2005 are classified in current assets and current liabilities.

Reclassifications. Prior year amounts relating to derivative liabilities and assets have been reclassified to disclose the current portion of those assets under current assets and liabilities in the Company's consolidated balance sheets. Since the Company defers the effects of SFAS 133, under a VPSB issued accounting order, (See Note A. Significant Accounting Policies - Derivative Instruments), there is an equal and opposite effect from reclassifying the corresponding current portions of the associated regulatory assets and liabilities. Current assets and liabilities increased by identical amounts and the reclassifications had no effect on the Company's working capital, no effect on the Company's liquidity and nearly no effect on any liquidity ratios. The derivatives were previously disclosed in 2004 under deferred charges and deferred credits with the corresponding regulatory assets and liabilities appearing net. In addition, certain prior year amounts have been reclassified on the cash flow statement for consistent presentation with the current year.

Other Comprehensive Income. 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 pension 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 has recorded other comprehensive losses reflecting additional minimum pension liabilities relating to qualified and non-qualified plans. Other comprehensive loss of $2.4 million, net of a $1.6 million income tax, was recognized during 2002 as a result of a minimum pension funding liability. During 2003, an increase in the market value of pension plan assets resulted in a reduction in other comprehensive loss of approximately $587,000, net of $400,000 income tax. During 2004, due principally to a decline in the discount rate assumption used for pension calculations, we recorded an increase in other comprehensive loss of $566,000, net of $391,000 income tax. During 2005, due principally to a decline in the discount rate assumption used for plan calculation, we recorded an increase in other comprehensive loss of $910,000, net of $620,000 income tax.

Recent Accounting Pronouncements. On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 ("the Act"). The Act expanded Medicare to include, for the first time, coverage for prescription drugs, generally effective January 1, 2006. The Company provides health care, life insurance, prescription drug and other benefits to retired employees who meet certain age and years of service requirements.

On May 19, 2004, the FASB issued FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," which requires employers to provide certain disclosures regarding the effect of the federal subsidy provided by the Act.

Pending the release of final regulations, the Company was unable to conclude whether the benefits provided by the plan were actuarially equivalent to Medicare Part D under the Act, and to accurately measure the effect of the change on the accumulated postretirement benefit obligation ("APBO") or the net periodic postretirement benefit cost ("net periodic cost"). This was a result of uncertainty with treatment under the Act of contributions made by certain retirees and the Company's cap on employer medical premiums. Regulations and their interpretations were finalized in January 2004, and the reduction in APBO at December 31, 2004, was determined to be approximately $3.5 million. The expected subsidy impacts annual net periodic cost in 2005 and beyond.

In December 2004, the FASB issued SFAS No. 123(Revised), "Share-Based Payments," which replaces SFAS No. 123. The revision determines how the Company will measure the cost of employee services received in exchange for share-based payments. The cost of share-based payments will be based on the grant date fair value of the award. The Company uses the fair value method for share-based payment awards and predicts that this new standard will not have a material impact on its financial position, its results of operations or its liquidity.

In December 2004, the FASB issued FASB Staff Position 109-1 ("FSP 109-1"), which was effective upon issuance, to provide guidance of the application of SFAS No. 109, "Accounting for Income Taxes" ("SFAS 109"), to the provision within the American Jobs Creation Act of 2004 ("Jobs Act") that provides a tax deduction on qualified production activities. The Jobs Act includes a tax deduction of up to 9 percent (when fully phased-in) of the lesser of (a) "qualified production activities income," as defined in the Jobs Act, or (b) taxable income (after the deduction for the utilization of any net operating loss carryforwards). The tax deduction is limited to 50 percent of W-2 wages paid by the taxpayer. FSP 109-1 clarifies that the manufacturer's deduction provided for under the Jobs Act should be accounted for as a special deduction in accordance with SFAS 109 and not as a tax rate reduction. The Company estimates its tax deduction on qualified production activities approximates $82,000.

On May 25, 2005, the Financial Accounting Standards Board ("FASB") issued Statement No. 154, *Accounting Changes and Error Corrections - a replacement of APB Opinion No. 20 and FASB Statement No. 3* ("SFAS 154"). This Statement replaces APB Opinion No. 20, Accounting Changes, and FASB Statement No. 3, *Reporting Accounting Changes in Interim Financial Statements*, and changes the requirements for the accounting for and reporting of a change in accounting principles. This Statement applies to all voluntary changes in accounting principle and changes required by an accounting pronouncement in the instance that the pronouncement does not include specific transition provision. SFAS 154 had no effect on the financial statements of the Company.

As of December 31, 2005, the Company adopted FIN 47, which clarified that a legal obligation associated with the retirement of a long-lived asset whose timing and/or method of settlement are conditional on a future event is within the scope of SFAS No. 143, *Accounting for Asset Retirement Obligations*. Under FIN 47, the Company is required to record liabilities associated with its conditional asset retirement obligation ("ARO") at their estimated fair values if those fair values can be reasonably estimated.

The Company measured its conditional AROs at fair value using the methodology prescribed by FIN 47 and recorded a resulting regulatory asset of approximately $344,000 under SFAS No. 71. Adoption of FIN 47 had no material impact on the financial position, results of operation or liquidity of the Company.

B. INVESTMENTS IN ASSOCIATED COMPANIES

The Company accounts for investments in the following associated companies by the equity method:

	Percent Ownership at December 31,		Investment in Equity at December 31,	
	2005	2004	2005	2004
			(In thousands)	
VELCO-common	29.17%	29.17%	$ 7,048	$ 7,041
VELCO-preferred	30.00%	30.00%	68	158
Total VELCO			7,116	7,199
VYNPC- Common	33.60%	33.60%	1,601	1,612
New England Hydro Transmission-Common	3.18%	3.18%	485	515
New England Hydro Transmission Electric-Common	3.18%	3.18%	834	853
Total investment in associated companies			$ 10,036	$ 10,179

VELCO. VELCO and its wholly-owned subsidiary, Vermont Electric Transmission Company, own and operate transmission systems in Vermont over which bulk power is delivered to all electric utilities in the state. VELCO operates under the terms of the 1985 Four-Party Agreement (as amended) with the Company and two other major distribution companies in Vermont.

VELCO has entered into transmission agreements with the State of Vermont and other electric utilities including the Company, and under these agreements, VELCO bills all costs, including interest on debt and a fixed return on equity, to the State and others, including the Company, using VELCO's transmission system. The Company is entitled to approximately 29 percent of the dividends distributed by VELCO. The Company has recorded its equity in earnings on this basis and also is required to pay for its share of VELCO's operating costs including debt service costs. The Company plans to make capital investments of up to $26 million in VELCO through 2008 in support of various transmission projects.

Summarized unaudited financial information for VELCO is as follows:
At and for the years ended December 31,

	2005	2004	2003
		(In thousands)	
Net income	$ 3,018	$ 1,683	$ 1,270
Company's equity in net income	$ 877	$ 472	$ 418
Total assets	$ 187,549	$ 145,632	$ 126,793
Liabilities and long-term debt	163,142	120,983	117,393
Net assets	$ 24,407	$ 24,649	$ 9,400
Company's equity in net assets	$ 7,116	$ 7,199	$ 2,657
Amounts due from (to) VELCO	$ 1,596	$ (4,068)	$ (4,190)

VELCO provided transmission services to the Company (reflected as transmission expenses in the accompanying Consolidated Statements of Income) amounting to $1.5 million in 2005, $12.3 million in 2004 and $12.0 million in 2003, respectively. Amounts decreased in 2005 because ISO-NE now invoices the Company directly for transmission services. Previously, ISO-NE invoiced VELCO and VELCO invoiced the Company for those transmission services.

Included in the Company's retail and other revenues are construction services of approximately $4.8 million billed to VELCO in 2005.

Vermont Yankee Nuclear Power Corporation ("VYNPC"). The Company's ownership share of VYNPC has increased from approximately 19.0 percent to approximately 33.6 percent in 2003, due to VYNPC's purchase of certain minority shareholders' interests in 2003. The Company's entitlement to energy produced by the Vermont Yankee nuclear plant owned by ENVY remains at approximately 20 percent of plant production.

Summarized unaudited financial information for VYNPC is as follows:
At and for the years ended December 31,

		2005		**2004**		**2003***
				(In thousands)		
Earnings:						
Operating revenues	$	160,613	$	167,399	$	187,123
Net income applicable to common stock		660		538		2,536
Company's equity in net income	$	221	$	181	$	498
Total assets	$	153,132	$	151,542	$	150,720
Liabilities and long-term debt		148,371		146,747		145,946
Net Assets	$	4,761	$	4,795	$	4,774
Company's equity in net assets	$	1,601	$	1,612	$	1,605
Amounts due to VYNPC	$	3,077	$	3,324	$	2,648

**The 2003 decrease in equity in net assets of VYNPC resulted from a distribution of proceeds, in the form of dividends to VYNPC owners, from the sale of the VYNPC nuclear power plant.*

On July 31, 2002, VYNPC announced that the sale of the Vermont Yankee nuclear power plant to ENVY had been completed. Since the Company no longer owns an interest in the Vermont Yankee nuclear plant, we are not responsible for the costs of decommissioning the plant, nor are we responsible for any plant repairs or maintenance costs during outages. See Note J for further information concerning our long-term power contract with VYNPC.

ENVY has announced that, under current operating parameters, it will exhaust the capacity of its existing nuclear waste storage pool in 2007 or 2008 and will need to store nuclear waste in so-called "dry fuel storage" facilities to be constructed on the site. Vermont law requires ENVY to obtain approval of the Vermont State legislature, in addition to VPSB approval, to construct and use such dry fuel storage facilities. ENVY received approval from the legislature in 2005 and is awaiting approval from the VPSB. If ENVY is unsuccessful in receiving favorable regulatory approval, ENVY has announced that it could be required to shut down the Vermont Yankee plant between 2007 and 2008. If the Vermont Yankee plant is shut down in 2007 and 2008, we would have to acquire substitute baseload power resources, comprising approximately 35 percent of our load. At projected forward market prices at December 31, 2005 for 2006, we estimate the annual incremental cost (in excess of the projected costs of power under our power supply contract for output from the Vermont Yankee plant) would be approximately $47 million annually. Recovery of those increased costs in rates would require a rate increase of approximately 23 percent.

On June 18, 2004, a fire in the electrical conduits leading to a transformer outside the plant resulted in a shutdown of the Vermont Yankee nuclear plant. The outage ended on July 7, 2004. In response to the Company's request, the

VPSB issued a final accounting order allowing the Company to defer its incremental replacement power costs during the outage totaling approximately $500,000. The order also instructs the Company to apply any proceeds received under a Ratepayer Protection Proposal ("RPP") to reduce the balance of deferred replacement power costs.

The RPP was a part of ENVY's request to uprate or increase the output of the Vermont Yankee nuclear plant that was approved by the VPSB. Under the RPP, we have indemnification rights to between approximately $550,000 and $1.6 million to recover uprate-related reductions in output for the three-year period beginning in May 2004 and ending after completion of the uprate (or a maximum of three years), depending on future wholesale energy market prices. ENVY disputes that the fire was uprate-related. The Company has petitioned the VPSB to resolve the dispute.

The Vermont Yankee plant received final approval for uprating from the Nuclear Regulatory Commission on March 2, 2006. The plant production will now be gradually increased and monitored as the plant progresses to its new full-power output of approximately 640 megawatts. After the Vermont Yankee nuclear plant uprating is completed, our percentage of energy output under Vermont Yankee's contract with ENVY would decline proportionately such that we would receive the same quantity of energy from the plant. In the event that ENVY were later derated, then our rights to energy output would decline proportionately to the derating. If this were to occur, we estimate it would have a material adverse effect on power supply costs. In this event we would seek recovery of these costs from the VPSB.

C. COMMON STOCK EQUITY AND STOCK AWARD PLANS

The Company maintains a Dividend Reinvestment and Stock Purchase Plan ("DRIP") under which 416,328 shares were reserved and unissued at December 31, 2005. The Company also funds an Employee Savings and Investment Plan ("ESIP") under which the Company may contribute shares of common stock. Under our ESIP plan, we match up to the first four percent of annual base salary and make an additional contribution of a half percent of base salary on a non-matching basis. Matching contributions are currently made in cash and immediately vest. We contributed $524,000, $487,000 and $398,000 for 2005, 2004 and 2003, respectively.

During 2000, the Company's Board of Directors, with subsequent approval of the Company's common shareholders, established a stock incentive plan (the "2000 Stock Plan"). Under this plan, up to 500,000 shares of common stock may be issued in the form of options, stock grants, stock appreciation rights, restricted stock, restricted stock units, performance awards and other stock-based awards to any employee, officer, consultant, contractor or director providing services to the Company, or its subsidiaries. The Company has previously issued stock options, stock awards and deferred stock units to employees and directors under the plan. Outstanding options become exercisable at between one and four years after the grant date and remain exercisable until 10 years from the grant date. As of December 31, 2005, no shares were unissued under the 2000 Stock Plan.

During 2004, the Company's Board of Directors, with subsequent approval of the Company's common shareholders, established the 2004 Stock Incentive Plan, under which 225,000 shares in the form of stock grants, options, stock appreciation rights, restricted stock and restricted stock units, performance awards or other stock-based awards can be granted to any employee, officer, consultant, contractor or director providing services to the Company, or its subsidiaries. As of December 31, 2005, 23,000 shares have been issued under the 2004 Stock Incentive Plan.

Under SFAS No. 123 (Revised), any equity based compensation awards will be measured at fair market value and expensed over the period in which services are provided.

Prior to 2003, as permitted by SFAS 123, the Company had elected to follow Accounting Principles Board Opinion No. 25 ("APB 25") "Accounting for Stock Issued to Employees," and related interpretations in accounting for its employee stock options issued through 2002. Effective January 1, 2003, the Company elected to expense the fair value of options granted beyond that date. The amount of expense recorded during 2003 was immaterial, and no options were granted in 2004 or 2005. Options have been issued only to employees and directors.

The fair values of options granted in 2003 was $1.33 per share. The fair value was estimated at the grant date using the Black-Scholes option-pricing model. The following table presents information about the assumptions that were used for each plan year, and a summary of the options outstanding at December 31, 2005:

				Assumptions used in option pricing model			
Plan year	Weighted average exercise price	Outstanding options	Remaining Contractual Life	Risk Free Interest rate	Expected Life in Years	Expected Stock Volatility	Dividend Yield
2000	$ 7.90	102,100	4.6 years	6.05%	5	30.58	4.5%
2001	$ 16.78	8,600	5.7 years	5.25%	6	32.69	4.0%
2002	$ 17.97	35,400	6.6 years	4.50%	6.5	16.89	4.5%
2003	$ 20.54	500	7.3 years	2.48%	6	13.68	4.5%
Total	$ 11.07	146,600					

	Total Options	Weighted Average Price	Range of Exercise Prices	Options Exercisable
Outstanding at December 31, 2002	365,800	11.23	$ 7.90-$17.82	151,775
Granted	4,000	20.55	$ 20.22-$22.62	
Exercised	64,550	10.63	$ 7.90-$18.67	
Forfeited	4,400	17.36	$ 16.78-$18.12	
Outstanding at December 31, 2003	300,850	11.39	$ 7.90-$22.62	193,700
Granted	-	-	-	
Exercised	89,650	12.11	$ 7.90-$20.96	
Forfeited	1,900	18.65	$ 17.54-$20.96	
Outstanding at December 31, 2004	209,300	$ 11.07	$ 7.90-$22.62	213,500
Granted	-			
Exercised	62,500	$ 11.31	$ 7.90-$22.62	
Forfeited	200	$ 20.08	$ 17.54-$22.62	
Outstanding at December 31, 2005	146,600	$ 10.90	$ 7.90-$22.62	146,600

The following table presents a reconciliation of the average common shares to average common equivalent shares outstanding:

Reconciliation of net income available for common shareholders and average shares	For the Years Ended December 31		
	2005	2004 (in thousands)	2003
Net income before preferred dividends	$ 11,180	$ 11,584	$ 10,407
Preferred stock dividend requirement	-	-	3
Net income applicable to common stock	$ 11,180	$ 11,584	$ 10,404
Average number of common shares-basic	5,195	5,083	4,980

Dilutive effect of stock options	89	171	160
Average number of common shares-diluted	5,284	5,254	5,140

As part of our long-term stock incentive program, unrestricted stock grants and deferred stock unit grants have been made to employees, senior management and directors. Unrestricted stock grants are recognized as compensation expense based on the fair value of the awards at the grant date. Deferred stock units are recognized as deferred compensation based on the fair value of the award at the grant date and charged to expense over the required service period for each award. Awards to senior management vest over a two year service period. Total compensation expense from all stock awards to directors, employees and senior management totaled $1.4 million in 2005 and $1.2 million in 2004.

Common stock issuance from compensation programs during 2005 amounted to 92,844 shares. Of this amount, 62,500 shares were issued for exercised options, 20,444 shares were issued for employee stock grants and 9,900 shares were issued for grants to the Company’s Board of Directors. Common stock issuance from compensation programs during 2004 amounts to 107,264 shares. Of this amount, 89,650 shares were issued for exercised options, 9,914 shares were issued for employee stock grants and 7,700 shares were issued for grants to the Company’s Board of Directors.

Appropriated Retained Earnings. The Company had appropriated retained earnings of $379,000 and $353,000 at December 31, 2005 and 2004, respectively, relating to regulatory requirements arising from ownership of hydro-electric facilities.

Dividend Restrictions. Certain restrictions on the payment of cash dividends on common stock are contained in the Company’s indentures relating to long-term debt and in the Amended and Restated Articles of Incorporation. Under the most restrictive of such provisions, approximately $35.9 million of retained earnings were free of restrictions at December 31, 2005.

D. SHORT-TERM DEBT

The Company has a $30.0 million 364-day revolving credit agreement with Fleet Financial Services ("Fleet") joined by Sovereign Bank ("Sovereign"), expiring June 14, 2006 (the "Fleet-Sovereign Agreement"). The Fleet-Sovereign Agreement is unsecured, and allows the Company to choose any blend of a daily variable prime rate and a fixed term LIBOR-based rate. Under the Fleet-Sovereign Agreement, there was no balance outstanding at December 31, 2005, and $3.0 million outstanding at a weighted average rate of 4 percent, at December 31, 2004. There was no non-utility short-term debt outstanding at December 31, 2005 or 2004.

The Fleet-Sovereign Agreement requires the Company to certify on a quarterly basis that it has not suffered a "material adverse change." The agreement also requires the Company to comply with certain covenants. The Company was in compliance with all covenants at December 31, 2005.

E. LONG-TERM DEBT

Substantially all of the property and franchises of the Company are subject to the lien of the indenture under which first mortgage bonds have been issued. The weighted average rate on long-term borrowings outstanding was 7.0 percent for both December 31, 2005 and 2004. The annual sinking fund requirements (excluding amounts that may be satisfied by property additions) are included in the following table with interest rates and maturities as of December 31 for the years presented.

LONG-TERM DEBT	At December 31,	
First Mortgage Bonds	**2005**	**2004**

Interest Rate	Maturity	Annual Sinking Fund	(In thousands)	
7.18%	Nov. 6, 2006	-	$ 10,000	$ 10,000
7.05%	Dec. 15, 2006	-	4,000	4,000
6.04%	Dec. 1, 2017	$6,000,000 begins 2011	42,000	42,000
6.70%	Nov. 1, 2018	-	15,000	15,000
9.64%	Sept. 1, 2020	-	9,000	9,000
8.65%	Mar. 1, 2022	$500,000 begins 2012	13,000	13,000
Total Long-term Debt Outstanding			93,000	93,000
Less Current Maturities (due within one year)			14,000	-
Total Long-term Debt, less current maturities			$ 79,000	$ 93,000

F. INCOME TAXES

Utility. The Company accounts for income taxes using the liability method. This method accounts for deferred income taxes by applying statutory rates to the differences between the book and tax bases of assets and liabilities.

The temporary differences, which gave rise to the net deferred tax liability at December 31, 2005 and December 31, 2004, were as follows:

	At December 31,			
		2005		**2004**
	(In thousands)			
Deferred Tax Assets				
Contributions in aid of construction	$	2,629	$	2,155
Deferred compensation and postretirement benefits		5,664		4,972
Self insurance and other reserves		405		639
Other		3,291		1,654
	$	11,989	$	9,420
Deferred Tax Liabilities				
Accelerated Tax Depreciation on Property	$	32,065	$	32,453
Demand side management		2,364		2,955
Deferred purchased power costs		818		1,033
Pine Street reserve		2,742		2,753
Other		2,198		2,449
	$	40,187	$	41,643
Net accumulated deferred income tax liability	$	28,198	$	32,223

The change in the net accumulated deferred income tax liability arises from the deferred income tax expense included in the income statement for the periods presented, the change in the tax effect of minimum pension funding liability changes, and the change in the tax effect of changes in income tax related regulatory assets and liabilities.

The components of the provision for income taxes are as follows:

	For the Years ended December 31,		
	2005	2004	2003
		(In thousands)	
Current federal income taxes	$ 6,326	$ 461	$ 2,434
Current state income taxes	1,913	1,602	1,207
Total current income taxes	8,239	2,063	3,641
Deferred federal income taxes	(1,938)	3,843	1,307
Deferred state income taxes	(341)	140	454
Total deferred income taxes	(2,279)	3,983	1,761
Investment tax credits-net	(284)	(284)	(282)
Income tax expense	$ 5,676	$ 5,762	$ 5,120

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

	For the Years ended December 31,		
	2005	2004	2003
		(In thousands)	
Income before income taxes and preferred dividends	$ 16,856	$ 17,346	$ 15,527
Federal statutory rate	35.0%	35.0%	34.0%
Computed "expected" federal income taxes	$ 5,900	$ 6,071	$ 5,279
Increase (decrease) in taxes resulting from:			
Tax versus book depreciation basis difference	91	(149)	41
Dividends received deduction	(350)	(452)	(465)
Amortization of ITC	(284)	(284)	(282)
State tax	1,022	1,133	1,082
Excess deferred taxes	(60)	(123)	(60)
Energy credits and production deduction	(375)	(125)	(130)
Other	(268)	(309)	(345)
Total federal and state income tax	$ 5,676	$ 5,762	$ 5,120
Effective combined federal and state income tax rate	33.7%	33.0%	34.5%

G. PENSION AND RETIREMENT PLANS

The Company has a qualified non-contributory defined benefit pension plan (the "Pension Plan") covering substantially all of its employees. The retirement benefits are based on the employees' level of compensation and length of service. Under the terms of the Pension Plan, employees are vested after completing five years of service, and can retire when they reach age 55 with a minimum of 10 years of service. The Company records annual expense and accounts for its pension plan in accordance with Statement of Financial Accounting Standards No. 87, *Employers' Accounting for Pensions*. The Company provides a non-qualified retirement plan for certain employees. Benefits under the non-qualified plan are funded on a cash basis.

The Company also provides certain health care benefits for retired employees and their dependents. Employees become eligible for these benefits if they reach retirement age while working for the Company. The Company accrues the cost of these benefits during the service life of covered employees. The Pension Plan and postretirement health care assets consist primarily of equity securities, fixed income securities, hedge funds and cash equivalent funds.

The Company's funding policy is to make voluntary contributions to its defined benefit plans to meet or exceed the minimum funding requirements of ERISA or the Pension Benefit Guaranty Corporation, and so long as the Company's liquidity needs do not preclude such investments. The Company made voluntary defined benefit plan contributions totaling $2.0 million during 2005 and $3.5 million during 2004. The Company currently plans to contribute approximately $2.0 million of additional funds during 2006.

During 2004, the Company increased its previously recognized minimum pension liability by $1 million to approximately $4 million, primarily as a result of a decrease in the pension plan discount rate assumption. Common equity decreased approximately $566,000, net of applicable income tax, through a charge to comprehensive income.

During 2005, the Company increased its previously recognized minimum pension liability by $1.5 million to approximately $5.4 million, primarily as a result of a decrease in the pension plan discount rate assumption. Common equity decreased approximately $910,000, net of applicable income tax, through a charge to comprehensive income.

Accrued postretirement health care expenses are recovered in rates. In order to maximize the tax-deductible contributions that are allowed under IRS regulations, the Company amended its postretirement health care plan to establish a 401-h sub-account and separate VEBA trusts for its union and non-union employees. The VEBA plan assets consist primarily of cash equivalent funds, fixed income securities and equity securities. The following provides a reconciliation of benefit obligations, plan assets and funded status of the plans as of December 31, 2005 and 2004.

	At and for the years ended December 31,			
	Pension Plans' Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
	(In thousands)			
Change in projected benefit obligation:				
Projected benefit obligation prior year end	$ 41,531	$ 38,754	$ 18,979	$ 21,906
Service cost	1,229	1,122	306	335
Interest cost	2,371	2,290	1,013	1,165
Participant contributions	-	-	157	115
Plan change	549	-	-	-
Change in actuarial assumptions	-	-	-	-
Actuarial (gain) loss	1,880	1,363	(287)	(3,595)
Benefits paid	(1,964)	(1,924)	(1,156)	(947)
Administrative expense	(177)	(74)	-	-
Projected benefit obligation as of year end	$ 45,419	$ 41,531	$ 19,012	$ 18,979
Accumulated benefit obligation	$ 45,419	$ 41,531	$ 19,012	$ 18,979
Change in plan assets:				
Fair value of plan assets as of prior year end	$ 29,930	$ 27,867	$ 11,672	$ 10,229
Administrative expenses paid	(177)	(74)	-	-
Participant contributions	-	-	-	-
Employer contributions	2,011	1,860	250	700
Actual return on plan assets	2,417	2,201	508	852
Benefits paid	(1,964)	(1,924)	(124)	(109)
Fair value of plan assets as of year end	$ 32,217	$ 29,930	$ 12,306	$ 11,672

Funded status as of year end	$	(13,203)	$	(11,602)	$	(6,706)	$	(7,307)
Unrecognized transition obligation		-		-		2,296		2,624
Unrecognized prior service cost		1,566		1,243		(1,738)		(1,977)
Unrecognized net actuarial loss		9,910		8,345		5,317		5,322
Prepaid (accrued) benefits at year end	$	(1,727)	$	(2,014)	$	(831)	$	(1,338)

Net periodic pension expense and other postretirement benefit costs include the following components:

	For the years ended December 31,											
	Pension Plans						Other Postretirement Benefits					
	2005		2004		2003		2005		2004		2003	
	(In thousands)											
Service cost	$	1,229	$	1,123	$	858	$	306	$	335	$	496
Interest cost		2,371		2,290		2,167		1,013		1,165		1,316
Expected return on plan assets		(2,454)		(2,285)		(1,851)		(967)		(857)		(740)
Amortization of transition asset		-		-		(77)		-		-		-
Amortization of prior service cost		227		205		168		(239)		(239)		(58)
Amortization of the transition obligation		-		-		-		328		328		328
Recognized net actuarial gain		351		267		295		177		338		381
Net periodic benefit cost	$	1,724	$	1,600	$	1,560	$	618	$	1,070	$	1,723

Assumptions used to determine pension and postretirement benefit costs and the related benefit obligations were:

Assumptions used in benefit obligation measurement	For the years ended December 31,			
	Pension Plans		Other Postretirement Benefits	
	2005	2004	2005	2004
Weighted average assumptions as of year end:				
Discount rate	5.50%	5.75%	5.50%	5.75%
Expected return on plan assets	8.25%	8.25%	8.25%	8.25%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Medical inflation	-	-	10.00%	10.75%
Measurement date	12/31/2005	12/31/2004	12/31/2005	12/31/2004
Census date	1/1/2005	1/1/2004	1/1/2005	1/1/2004

Assumptions used in periodic cost measurement	For the years ended December 31,			
	Pension Plans		Other Postretirement Benefits	
	2005	2004	2005	2004
Weighted average assumptions as of year end:				

Discount rate	5.75%	6.00%	5.75%	6.00%
Expected return on plan assets	8.25%	8.25%	8.25%	8.25%
Rate of compensation increase	4.00%	4.25%	4.00%	4.25%
Current year trend	-	-	10.00%	9.25%
Ultimate year trend			5.00%	5.50%
Year of ultimate trend			2011	2009

For measurement purposes, a 10.00 percent annual rate of increase in the per capita cost of covered medical benefits was assumed for 2005. This rate of increase gradually declines to 5.0 percent in 2011. The medical trend rate assumption has a significant effect on the amounts reported. For example, increasing the assumed health care cost trend rate by one percentage point for all future years would increase the accumulated postretirement benefit obligation as of December 31, 2005 by 13.1 percent or $2.5 million and the total of the service and interest cost components of net periodic postretirement cost for the year ended December 31, 2005 by $186,000, or 14.1 percent. Decreasing the trend rate by one percentage point for all future years would decrease the accumulated postretirement benefit obligation at December 31, 2005 by 10.4 percent or $2.0 million, and the total of the service and interest cost components of net periodic postretirement cost for 2005 by $143,000, or 10.8 percent.

The Company's defined benefit plan investment policy seeks to achieve sufficient growth to enable the defined benefit plans to meet their future obligations and to maintain certain funded ratios and minimize near-term cost volatility. Current guidelines specify generally that 65 percent of combined plan assets be invested in equity securities, 30 percent of combined plan assets be invested in debt securities and the remainder be invested in alternative investments.

The Company expects an annual long-term return for the defined benefit plan asset portfolios 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 expected capital market performance of the next ten years.

Weighted Average Asset Allocation Asset Category	**Pension Plans' Assets**			**Other Postretirement Benefit Assets**		
	For the years ended December 31,					
	2006 Target	**2005**	**2004***	**2006 Target**	**2005**	**2004**
Equity Securities	65.00%	66.60%	48.96%	65.00%	65.00%	63.00%
Debt Securities	30.00%	18.71%	25.80%	35.00%	31.00%	32.00%
Real Estate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Other	0.00%	6.31%	19.94%	0.00%	4.00%	5.00%
Alternative investments	5.00%	8.38%	5.30%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

*The large difference between the target and actual allocations is due to a $5 million cash transfer between funds at December 31, 2004

	Pension Plans Projected Benefit	Other Postretirement Benefits Projected Benefit

In Thousands	Contributions	payments	Contributions	payments
2006	$ 1,608	$ 2,048	$ 769	$ 769
2007	1,839	2,028	500	755
2008	2,278	2,548	500	726
2009	1,968	2,297	500	685
2010	1,823	2,186	500	718
2011 through 2015	10,521	14,231	2,500	3,943

The Company maintains a 401(k) Savings Plan for substantially all employees. This savings plan provides for employee contributions up to specified limits. The Company matches employee pre-tax contributions up to 4 percent, and contributes an additional one-half percent each year made on a non-matching basis, of eligible compensation. The additional half percent contribution was added effective January 2004. The Company match is immediately vested. The Company's matching and non-matching contributions for the years 2005, 2004, and 2003 were $524,000, $487,000 and $398,000, respectively.

H. COMMITMENTS AND CONTINGENCIES

Other contingencies are discussed under Note A, Regulatory Accounting and Major Customers and Other Concentration Risks and Note B, Vermont Yankee Nuclear Power Corporation ("VYNPC") and Note J Long-Term Power Purchases.

Environmental Matters

The electric industry typically uses or generates a range of potentially hazardous products in its operations. We must meet various land, water, air and aesthetic requirements as administered by local, state and federal regulatory agencies. We believe that we are in substantial compliance with these requirements, and that there are no outstanding material complaints about our compliance with present environmental protection regulations.

Pine Street Barge Canal Superfund Site - In 1999, the Company entered into a United States District Court Consent Decree constituting a final settlement with the United States Environmental Protection Agency ("EPA"), the State of Vermont and numerous other parties of claims relating to a federal Superfund site in Burlington, Vermont, known as the "Pine Street Barge Canal." The consent decree resolves claims by the EPA for past site costs, natural resource damage claims and claims for past and future remediation costs. The consent decree also provides for the design and implementation of response actions at the site. We have estimated total future costs of the Company’s future obligations under the consent decree to be approximately $6.1 million. The estimated liability is not discounted, and it is possible that our estimate of future costs could change by a material amount. We have recorded a regulatory asset of $12.9 million to reflect unrecovered past and future Pine Street costs. Pursuant to the Company’s 2003 Rate Plan, as approved by the VPSB, the Company began to amortize past unrecovered costs in 2005. The Company will amortize the full amount of incurred costs over 20 years without a return. The amortization is expected to be allowed in future rates, without disallowance or adjustment, until fully amortized.

Clean Air Act - The Company purchases most of its power supply from other utilities and does not anticipate that it will incur any material direct costs as a result of the Federal Clean Air Act or proposals to make more stringent regulations under that Act.

Jointly-Owned Facilities

The Company has joint-ownership interests in electric generating and transmission facilities at December 31, 2005, as follows:

	Ownership Interest	Share of Capacity	Share of Utility Plant	Share of Accumulated Depreciation
	(In %)	(In MW)	(In thousands)	
Highgate	33.8	67.6	$ 10,482	$ 5,470
McNeil	11.0	5.9	9,108	5,971
Stony Brook (No. 1)	8.8	31.0	11,390	9,895
Wyman (No. 4)	1.1	6.8	1,980	1,506
Metallic Neutral Return	59.4	-	1,563	931

Metallic Neutral Return is a neutral conductor for the NEPOOL/Hydro-Quebec Interconnection

The Company's share of expenses for these facilities is reflected in Operating Expenses in the Consolidated Statements of Income under Company-owned generation for the three listed generation plants and under Transmission for the Metallic Neutral Return and Highgate facilities. Each participant in these facilities must provide its own financing.

Rate Matters

Retail Rate Cases - On December 22, 2003, the VPSB approved our 2003 Rate Plan, jointly proposed by the Company and the Vermont Department of Public Service ("DPS"). The 2003 Rate Plan covers the period from 2003 through 2006 and includes the following principal elements:

* The Company’s rates remained unchanged through 2004. The 2003 Rate Plan allows the Company to raise rates 1.9 percent, effective January 1, 2005, and an additional 0.9 percent, effective January 1, 2006. We submitted a cost of service schedule supporting the rate increases for 2005 and 2006 in accordance with the plan and the increases became effective on January 1, 2005 and January 1, 2006. The VPSB retains the discretion to open an investigation of the Company’s rates at any time, at the request of the DPS, the request of ratepayers, or on its own volition. The Company may seek additional rate increases in extraordinary circumstances, such as severe storm repair costs, natural disasters, unanticipated unit outages, or significant losses of customer load.

* The Company’s allowed return on equity is 10.5 percent for the period January 1, 2003 through December 31, 2006. During the same period, the Company’s earnings on utility operations are capped at 10.5 percent. Excess earnings in 2005 or 2006 will be refunded to customers as a credit on customer bills or applied to recover regulatory assets, as the Department directs.

* The Company carried forward into 2004 $3.0 million in deferred revenue remaining at December 31, 2003, from the Company’s 2001 Settlement Order (summarized below). These revenues were applied in 2004 to offset increased costs.

* The Company is to amortize (recover) certain regulatory assets, including Pine Street Barge Canal environmental site costs and past demand-side management program costs, beginning in January 2005, with those costs to be allowed in future rates. Pine Street costs will be recovered over a twenty-year period without a return.

    * The Company and the Department have agreed to work cooperatively to develop and propose an alternative regulation plan as authorized by legislation enacted in Vermont in 2003.

In January 2001, the VPSB issued the 2001 Settlement Order, which included the following:

* Rates were set at levels that recover the Company’s VJO Contract costs, effectively ending the regulatory disallowances experienced by the Company from 1998 through 2000;

* The Company and customers shall share equally any premium above book value realized by the Company in any future merger, acquisition or asset sale, subject to an $8.0 million limit on the customers' share, adjusted for inflation; and

* The Company's further investment in non-utility operations was restricted until new rates went into effect, which occurred in January 2005. Although this restriction has expired, we have no plans to make material investments in non-utility operations.

Accounting Order

During February 2006, the Company requested that the VPSB grant an accounting order to allow us to defer approximately $3.7 million in incremental hurricane-related power supply expenses to be incurred in the first quarter of 2006, and to also allow the Company to defer and amortize $1.3 million of incremental hurricane-related benefits realized in the fourth quarter of 2005 against these costs. The accounting order was approved by the VPSB in February 2006.

Other Legal Matters

In 2002, the owners of property along the shoreline of Joe's Pond, an impoundment located in Danville, Vermont, created by the Company's West Danville hydroelectric generating facility, filed an inquiry with the VPSB seeking review of certain dam improvements made by the Company in 1995, alleging that the Company did not obtain all necessary regulatory approvals for the 1995 improvements and that the Company's improvements and subsequent operation of the dam have caused flooding of the shoreline and property damage. The Company received VPSB approval for, and has made additional dam improvements, at the facility. The Company and the Department stipulated to a penalty of $50,000 on the matter. The VPSB approved the stipulation in July 2005 and the penalty has been paid. In addition, numerous owners of shoreline property on Joe’s Pond have filed a lawsuit in Vermont superior court seeking damages for property damage allegedly caused by the Company’s negligent conduct in operating and maintaining the dam. The Company does not expect the litigation to result in a material adverse effect on its operating results or financial condition.

I. OBLIGATIONS UNDER TRANSMISSION INTERCONNECTION SUPPORT AGREEMENT AND OTHER LEASES

Agreements executed in 1985 among the Company, VELCO and other NEPOOL members and Hydro Quebec provided for the construction of the second phase (Phase II) of the interconnection between the New England electric systems and that of Hydro Quebec. Phase II provides 2,000 megawatts of capacity for transmission of Hydro Quebec power to Sandy Pond, Massachusetts. Construction of Phase II commenced in 1988 and was completed in late 1990. The Company is entitled to 3.2 percent of the Phase II power-supply benefits. Total construction costs for Phase II were approximately $487 million. The New England participants, including the Company, have contracted to pay monthly their proportionate share of the total cost of constructing, owning and operating the Phase II facilities, including capital costs. As a supporting participant, the Company must make support payments under thirty-year agreements. These support agreements meet the capital lease accounting requirements. At December 31, 2005, the present value of the Company's obligation is approximately $3.9 million.

Projected future minimum payments under the Phase II support agreements are as follows:

	For the Years ending December 31 (In thousands)
2006	$ 385

2007		385
2008		385
2009		385
2010		385
Total for 2011-2015		1,928
Total	$	3,853

The Phase II portion of the project is owned by New England Hydro-Transmission Electric Company and New England Hydro-Transmission Corporation, subsidiaries of National Grid USA. Certain of the Phase II participating utilities, including the Company, own equity interests in such companies. The Company holds approximately 3.2 percent of the equity of the corporations owning the Phase II facilities and accounts for its ownership under the equity method of accounting.

J. LONG-TERM POWER PURCHASES

Unit Purchases.

Under long-term contracts with various electric utilities in the region, the Company is purchasing certain percentages of the electrical output of production plants constructed and financed by those utilities. Such contracts obligate the Company to pay certain minimum annual amounts representing the Company's proportionate share of fixed costs, including debt service requirements, whether or not the production plants are operating. The cost of power obtained under such long-term contracts, including payments required when a production plant is not operating, is reflected as "Purchases from others" in the accompanying Consolidated Statements of Income.

Purchased power expense by significant contract supplier

	for the Years ended December 31,					
		2005		**2004**		**2003**
In thousands						
Hydro Quebec	$	50,112	$	48,309	$	46,367
Morgan Stanley		12,563		11,106		59,311
VYNPC		32,409		33,331		38,109
Small Power Producers		16,486		15,832		15,277
Stony Brook		1,667		1,696		2,222

Information, including estimates for the Company's portion of certain minimum costs, with regard to significant purchased power contracts of this type in effect during 2005 follow.

Vermont Yankee.

The Company has a long-term power purchase contract with VYNPC, which sold its nuclear power plant to ENVY on July 31, 2002. The Company is no longer required to pay its proportionate share of fixed costs, including costs to decommission the plant, associated with the ENVY plant, including when the plant is not operating, though the Company is responsible for finding replacement power at such times.

The VYNPC sale of its nuclear power plant to ENVY also calls for ENVY, through its power contract with VYNPC, to provide 20 percent of the plant output to the Company through 2012, which represents approximately 35 percent of the Company’s energy requirements.

A summary of the Purchase Power Agreement ("PPA"), including projected charges for the years indicated, follows:

(Dollars in thousands except per KWh)			VYNPC Contract
Capacity acquired			106 MW
Contract period expires			2012
Company's share of output			20%
Annual energy charge	2005	$	32,409
estimated	2006-2012	$	33,595
Average cost per KWh	2005	$	0.040
estimated	2006-2012	$	0.042

Prices under the PPA range from $39 to $45 per megawatt hour. The PPA contains a provision known as the "low market adjuster," which calls for a downward adjustment in the contract price if market prices for electricity fall by defined amounts beginning November 2005. If market prices rise, however, PPA prices are not adjusted upward in excess of the PPA price.

The Company remains responsible for procuring replacement energy at market prices during periods of scheduled or unscheduled outages at the ENVY plant.

Hydro Quebec.
Under various contracts, summarized in the table below, the Company purchases capacity and associated energy produced by the Hydro Quebec system. Such contracts obligate the Company to pay certain fixed capacity costs whether or not energy purchases above a minimum level set forth in the contracts are made. Such minimum energy purchases must be made whether or not other, less expensive, energy sources might be available. These contracts are intended to complement the other components in the Company's power supply to achieve the most economic power supply mix available. The Company's current purchases pursuant to the contract with Hydro Quebec entered into in December 1987 (the "VJO Contract") are as follows: (1) Schedule B -- 68 megawatts of firm capacity and associated energy to be delivered at the Highgate interconnection for twenty years beginning in September 1995; and (2) Schedule C3 -- 46 megawatts of firm capacity and associated energy to be delivered at interconnections to be determined at any time for 20 years, which began in November 1995. There are specific step-up provisions that provide that in the event any VJO Contract participant fails to meet its obligation under the VJO Contract with Hydro Quebec, the remaining contract participants, including the Company, will step-up to the defaulting participant's share on a prorated basis.

In accordance with guidance set forth in FIN 45, the Company is required to disclose the "maximum potential amount of future payments (undiscounted) the guarantor could be required to make under the guarantee." Such disclosure is required even if the likelihood of triggering the guarantee is remote. In regards to the "step-up" provision in the VJO Contract, the Company must assume that all other members of the VJO simultaneously default in order to estimate the "maximum potential" amount of future payments. The Company believes this is a highly unlikely scenario given that the majority of VJO members are regulated utilities with regulated cost recovery. Each VJO participant has received regulatory approval to recover the cost of this purchased power. Despite the remote chance that such an event could occur, the Company estimates that its undiscounted purchase obligation would be approximately $832 million for the remainder of the contract, assuming that all other members of the VJO defaulted by January 1, 2006 and remained in default for the duration of the contract. In such a scenario, the Company would then own the power and could seek to recover its costs from the defaulting members, its retail customers, or resell the power in the wholesale power markets in New England. The range of outcomes (full cost recovery, potential loss or potential profit) would be highly dependent on Vermont regulation and wholesale market prices at the time.

Hydro Quebec also had the right to reduce the load factor from 75 percent to 65 percent under the VJO Contract a total of three times over the life of the contract. During 2001, Hydro Quebec exercised the first of these options for 2002, and the Company delayed the effective date of this exercise until 2003. The net cost of Hydro Quebec's exercise of its option increased power supply expense during 2003 by approximately $1.2 million.

During 2003, Hydro Quebec exercised its second option to reduce the load factor for 2004 at an incremental expense of approximately $1.8 million. Hydro Quebec exercised its third option in 2004 for deliveries occurring principally during 2005 that resulted in an incremental expense of $3.9 million based on current market prices. Hydro Quebec also retains the right to curtail annual energy deliveries by 10 percent up to five times, over the 2001 to 2015 period, if documented drought conditions exist in Quebec. Under the VJO Contract, Vermont Joint Owners, including the Company, have two remaining options to adjust deliveries by a five percent load factor, and exercised the first of these options in the fourth quarter of 2005 for delivery effective November 1, 2005 to October 31, 2006.

The Company’s contracts with Hydro Quebec call for the delivery of system power and are not related to any particular facilities in the Hydro Quebec system. Consequently, there are no identifiable debt-service charges associated with any particular Hydro Quebec facility that can be distinguished from the overall charges paid under the contracts, and there are no generation plant outage risks, although there are outage risks related to the operation of the transmission system.

A summary of the Hydro Quebec contracts, including historic and projected charges for the years indicated, follows:

			The VJO Contract			
			Schedule B		**Schedule C3**	
			(Dollars in thousands except per KWh)			
Capacity acquired			68 MW		46 MW	
Contract period			1995-2015		1995-2015	
Minimum energy purchase (annual load factor)			65%-75%		65%-75%	
Annual energy charge		2005	$ 11,376		$ 7,872	
	estimated	2006-2015	$ 13,756	(1)	$ 9,400	(1)
Annual capacity charge		2005	$ 16,563		$ 11,595	
	estimated	2006-2015	$ 16,769	(1)	$ 11,501	(1)
Average cost per KWh		2005	$ 0.069		$ 0.070	
	estimated	2006-2015	$ 0.070	(2)	$ 0.070	(2)

(1) Estimated average includes load factor reduction to 65 percent in 2005.
(2) Estimated average in nominal dollars levelized over the period indicated includes amortization of payments to Hydro Quebec.

Under a separate agreement established in 1996 (the "9701 agreement"), Hydro Quebec provided a payment of $8.0 million to the Company in 1997. In return for this payment, the Company provided Hydro Quebec an option for the purchase of power. Commencing April 1, 1998, and effective through October 2015, Hydro Quebec can exercise an option to purchase up to 52,500 MWh ("option A") on an annual basis, at energy prices established in accordance with the VJO Contract. The cumulative amount of energy purchased under the 9701 agreement shall not exceed 950,000 MWh. Hydro Quebec's option to curtail energy deliveries pursuant to the VJO Contract may be exercised in addition to these purchase options.

Over the same period, Hydro Quebec could exercise an option on an annual basis to purchase a total of 600,000 MWh ("option B") at the VJO Contract energy price. Hydro Quebec could purchase no more than 200,000 MWh in any given contract year ending October 31. As of December 31, 2005, Hydro Quebec had purchased all MWh available under option B.

Hydro Quebec exercised options A and B for 2003, 2004 and 2005, and the Company purchased replacement power at a net cost of $4.5 million, $3.2 million and $2.7 million, respectively. The Company has also covered option A during 2006 at a net cost of $7.4 million. The Company has requested an accounting order from the VPSB to defer up to $2.4 million of this expense. Hydro Quebec's call for 2006 was made during the fourth quarter of 2005 for delivery during January and February, timed to take advantage of extremely high forward energy prices resulting from the effects of hurricanes Katrina and Wilma that interrupted gas production in the Gulf of Mexico. Energy prices in the northeast are heavily dependent upon natural gas prices.

Morgan Stanley Contract.
In February 1999, the Company entered into a contract with Morgan Stanley Capital Group, Inc. (the "Morgan Stanley Contract"). In August 2002, the Morgan Stanley Contract was modified and extended to December 31, 2006. The Morgan Stanley Contract price is substantially below current market prices. The Morgan Stanley Contract currently supplies approximately 17 percent of the Company's estimated customer demand ("load").

Under the Morgan Stanley Contract, on a daily basis, and at Morgan Stanley's discretion, we sell power to Morgan Stanley from part of our portfolio of power resources at predefined operating and pricing parameters. Morgan Stanley sells to the Company, at a predefined price, power sufficient to serve pre-established load requirements. We remain responsible for resource performance and availability. The Morgan Stanley Contract provides no coverage against major unscheduled power supply outages. Beginning January 1, 2004, the Company reduced the power that it sells pursuant to the Morgan Stanley Contract. The output of some of our power-supply resources, including purchases pursuant to our Hydro Quebec and VYNPC contracts, which were sold to Morgan Stanley through 2003, are no longer included in the Morgan Stanley Contract. This reduction in sales to Morgan Stanley reduced wholesale revenues by approximately $56.2 million during 2004 when compared with 2003, and correspondingly reduced power supply expense by a similar amount. This change did not adversely affect the Company's operating results or its opportunity to earn a fair rate of return during 2005.

The Company purchased or expects to purchase the following amounts from Morgan Stanley for the years indicated:

	The Morgan Stanley Contract
Capacity acquired*	1-182 MW
Contract period expires	2006
Annual energy charge :	
2004	$11.1 million
2005	$12.6 million
2006 estimate	$10.2 million

**Capacity ranges between 0 and 182 MW over the remaining contract life depending on the scheduled hour.*

The Company and Morgan Stanley have agreed to the protocols that are used to schedule power sales and purchases and to secure necessary transmission. The Morgan Stanley Contract is a derivative that includes a risk premium above expected future costs of electricity.

Unit Purchases.
Under a long-term contract with Massachusetts Municipal Wholesale Electric Company ("MMWEC"), the Company is purchasing a percentage of the electrical output of the Stony Brook production plant constructed by MMWEC. The contract obligates the Company to pay certain minimum annual amounts representing the Company's proportionate share of fixed costs, including debt service requirements, whether or not the production plant is operating, for the life

of the unit. The cost of power obtained under this long-term contract, including payments required when the production plant is not operating, is reflected as "Purchases from others" in the accompanying Consolidated Statements of Income.

Information (including estimates for the Company's portion of certain minimum costs and ascribed long-term debt) with regard to this purchased power contract in effect during 2005 follows:

		Stony Brook (Dollars in thousands)
Plant capacity		352.0 MW
Company's share of output		4.40%
Company's annual share of:		
Interest	$	87
Other debt service		489
Other capacity		534
Total annual capacity	$	1,110
Company's share of long-term debt	$	782

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, Vermont Electric Power Producers Inc. ("VEPPI"), which assigns power to all Vermont utilities under VPSB rules. In 2005, the Company received 131,774 MWh under these long-term contracts at a cost of $16.5 million. These IPP purchases amount to 6.0 percent of the Company's total MWh purchased and 11.5 percent of purchase power expenses. Estimated purchases from IPPs are expected to range between approximately $16.0 million and $17.0 million for the years 2006 through 2010.

K. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The following quarterly financial information, in the opinion of management, includes all adjustments necessary to a fair statement of results of operations for such periods. Variations between quarters reflect the seasonal nature of the Company's business and the timing of rate changes.

Amounts in thousands except per share data	2005 Quarter ended				
	March	**June**	**September**	**December**	**Total**
Operating revenues	$ 58,248	$ 54,888	$ 57,584	$ 75,140	$ 245,860
Operating income	4,326	3,647	3,839	4,269	16,081
Net income-continuing operations	$ 2,981	$ 2,384	$ 2,524	$ 3,157	$ 11,046
Net income-discontinued operations	(2)	(3)	18	121	134
Net Income applicable to common stock	$ 2,979	$ 2,381	$ 2,542	$ 3,278	$ 11,180
Basic earnings per share from:					
Continuing operations	$ 0.58	$ 0.46	$ 0.49	$ 0.58	$ 2.12
Discontinued operations	-	-	-	0.03	0.03
Basic earnings per share	$ 0.58	$ 0.46	$ 0.49	$ 0.61	$ 2.15
Weighted average common shares outstanding	5,160	5,186	5,208	5,224	5,195
Diluted earnings per share from:					
Continuing operations	$ 0.56	$ 0.45	$ 0.48	$ 0.60	$ 2.09
Discontinued operations	-	-	-	0.03	0.03
Diluted earnings per share	$ 0.56	$ 0.45	$ 0.48	$ 0.63	$ 2.12
Weighted average common and common equivalent shares outstanding	5,301	5,271	5,301	5,318	5,284

	2004 Quarter ended				
	March	**June**	**September**	**December**	**Total**
Operating revenues	$ 63,123	$ 54,585	$ 54,926	$ 56,182	$ 228,816
Operating income	5,019	2,776	4,595	3,088	15,478
Net income-continuing operations	$ 3,740	$ 1,783	$ 3,392	$ 2,144	$ 11,059
Net income-discontinued operations	(6)	(1)	(2)	534	525
Net Income applicable to common stock	$ 3,734	$ 1,782	$ 3,390	$ 2,678	$ 11,584
Basic earnings per share from:					
Continuing operations	$ 0.74	$ 0.35	$ 0.67	$ 0.42	$ 2.18
Discontinued operations	-	-	-	0.10	0.10
Basic earnings per share	$ 0.74	$ 0.35	$ 0.67	$ 0.52	$ 2.28
Weighted average common shares outstanding	5,046	5,072	5,089	5,124	5,083
Diluted earnings per share from:					
Continuing operations	$ 0.72	$ 0.34	$ 0.65	$ 0.39	$ 2.10
Discontinued operations	-	-	-	0.10	0.10
Diluted earnings per share	$ 0.72	$ 0.34	$ 0.65	$ 0.49	$ 2.20
	5,205	5,228	5,251	5,282	5,254

Weighted average common and common equivalent shares outstanding

	2003 Quarter ended				
	March	June	September	December	Total
Operating revenues	$ 72,945	$ 64,455	$ 71,975	$ 71,095	$ 280,470
Operating income	5,231	2,425	4,302	3,348	15,306
Net income-continuing operations	$ 4,084	$ 1,120	$ 3,034	$ 2,087	$ 10,325
Net income-discontinued operations	(13)	(8)	6	94	79
Net Income applicable to common stock	$ 4,071	$ 1,112	$ 3,040	$ 2,181	$ 10,404
Basic earnings per share from:					
Continuing operations	$ 0.82	$ 0.22	$ 0.61	$ 0.43	$ 2.08
Discontinued operations	-	-	-	0.01	0.01
Basic earnings per share	$ 0.82	$ 0.22	$ 0.61	$ 0.44	$ 2.09
Weighted average common shares outstanding	4,959	4,969	4,982	5,009	4,980
Diluted earnings per share from:					
Continuing operations	$ 0.80	$ 0.22	$ 0.59	$ 0.40	$ 2.01
Discontinued operations	-	-	-	0.01	0.01
Diluted earnings per share	$ 0.80	$ 0.22	$ 0.59	$ 0.41	$ 2.02
Weighted average common and common equivalent shares outstanding	5,118	5,129	5,141	5,165	5,140

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Green Mountain Power Corporation

We have audited the accompanying consolidated balance sheets of Green Mountain Power Corporation and subsidiaries (the "Company") as of December 31, 2005 and 2004, and the related consolidated statements of income, changes in shareholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Green Mountain Power Corporation and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 14, 2006 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

DELOITTE & TOUCHE LLP
Boston, Massachusetts
March 14, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Green Mountain Power Corporation

We have audited management's assessment, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*, that Green Mountain Power Corporation and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2005, of the Company and our report dated March 14, 2006 expressed an unqualified opinion on those financial statements.

DELOITTE & TOUCHE LLP
Boston, Massachusetts
March 14, 2006

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934, as amended, we carried out an evaluation, with the participation of our management, including our chief executive officer and chief financial officer, of the effectiveness of our disclosure controls and procedures (as defined under Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended) as of the end of the period covered by this report. Based upon that evaluation, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures were not effective as of such date due to an ineffective disclosure control relating to the requirement under Item 2.02 of Current Report on Form 8-K that we furnish to the Securities and Exchange Commission press releases announcing quarterly earnings. We issued and disseminated press releases of our earnings for the second and third quarter of 2005, and for the year ending December 31, 2005, but did not furnish on Current Reports on Form 8-K such earnings releases to the Securities and Exchange Commission in a timely manner. Our management discovered these missed submissions through its internal review processes and promptly thereafter furnished the appropriate Item 2.02 Current Reports on Form 8-K to the Securities and Exchange Commission. We have implemented enhanced disclosure controls and procedures to ensure that such submissions are timely made, including procedures requiring additional and enhanced management sign-off procedures in advance of issuance of earnings releases and required verification that earnings releases have been furnished on a Current Report on Form 8-K in a timely manner. Our chief executive officer and chief financial officer believe that, as a result of the implementation of these enhanced procedures, as of the date hereof our disclosure control and procedures are effective.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Under the supervision and with the participation of our management, including our chief executive officer and chief financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in “Internal Control - Integrated Framework” issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment under the criteria for effective internal control over financial reporting described in “Internal Control - Integrated Framework,” issued by the Committee of Sponsoring Organizations of the Treadway Commission, management determined that as of December 31, 2005, our internal control over financial reporting was effective.

Management’s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005 has been audited by Deloitte and Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Management’s report on our internal control over financial reporting was included in our Annual Report on Form 10-K for the year ended December 31, 2004 and concluded that, as of December 31, 2004, we did not maintain effective internal control over financial reporting due to a material weakness as a result of deficiencies in both the design and operating effectiveness of controls associated with our accounting for income taxes. Beginning in the first quarter of 2005 and continuing throughout the year, management conducted testing and enhancement of our internal controls associated with accounting for income taxes and engaged a public accounting firm to assist management with the review of all income tax entries for each quarter, the statutory rate reconciliation, our treatment of new tax credits and deductions, if applicable, and timing differences. These ongoing efforts, which required certain changes to our internal controls associated with accounting for income taxes, and which were subject to audit by our independent registered accounting firm at year-end, have improved the design and operating effectiveness of our control processes and systems for financial reporting. Based on these efforts, management believes that the deficiencies in both the design and operating effectiveness of controls associated with our accounting for income taxes have been remediated and that we no longer have a material weakness in our internal control over financial reporting with respect to this issue.

It should be noted that the design of any system of controls is based, in part, on certain assumptions about the likelihood of future events, and that only reasonable assurance can be given that any internal control system will succeed in achieving its stated goals against all potential future conditions, regardless of how remote.

Changes in Internal Controls

We continue to review, revise and improve the effectiveness of our internal control over financial reporting. Except as described above, we have made no change in our internal control over financial reporting in connection with our fourth quarter evaluation that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Pursuant to Item 1.01 of Current Report on Form 8-K, the Company provides the disclosures included in Exhibits 10.d.76 and 10.d.77 hereto.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Certain information regarding executive officers called for by Item 10, "Directors and Executive Officers of the Registrant," is furnished under the caption, "Executive Officers" in Item 1 of Part I of this Report. The other information called for by Item 10 will be set forth under the captions "Election of Directors," "Nominees for Election to the Board of Directors," "Information About Our Board of Directors" and "Section 16(a) Beneficial Ownership Reporting Compliance," in the Company's definitive proxy statement relating to its annual meeting of stockholders to be held on May 22, 2006. Such information is incorporated herein by reference. Such proxy statement pertains to the election of directors and other matters. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A in April 2006.

Because our common stock is listed on the New York Stock Exchange (the "NYSE"), our chief executive officer is required to make, and he has made, an annual certification to the NYSE stating that he was not aware of any violation by us of the corporate governance listing standards of the NYSE. Our chief executive officer made his annual certification to that effect to the NYSE as of June 3, 2005. In addition, we have filed, as exhibits to this Annual Report on Form 10-K, the certifications of our principal executive officer and principal financial officer required under Sections 906 and 302 of the Sarbanes Oxley Act of 2002 to be filed with the SEC regarding the quality of our public disclosure.

ITEMS 11, 12, 13 and 14

The information called for by Items 11, 12, 13 and 14, "Executive Compensation," "Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters," "Certain Relationships and Related Transactions," and "Principal Accounting Fees and Services," will be set forth under the captions "Executive Compensation and Other Information," "Compensation Committee Report on Executive Compensation," "Pension Plan Information and Other Benefits," "Equity Compensation Plan Information," "Securities Ownership of Certain Beneficial Owners and Management," and "Audit Committee Report" in the Company's definitive proxy statement relating to its annual meeting of stockholders to be held on May 22, 2006. Such information is incorporated herein by reference. Such proxy statement pertains to the election of directors and other matters. Definitive proxy materials will be filed with the Securities and Exchange Commission pursuant to Regulation 14A in April 2006.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

List of documents filed as part of this Form 10-K:

(1) Financial Statements. See the Index to the Company's financial statements set forth in Item 8 hereof.

(2) Financial Statement Schedules. N/A.

(3) Exhibits. See the Exhibit Index set forth at the end of this Form 10-K.

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.

Date: March 14, 2006	GREEN MOUNTAIN POWER CORPORATION By: /s/Christopher L. Dutton Christopher L. Dutton, President And Chief Executive Officer

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 and on the dates indicated.

SIGNATURE	TITLE	DATE
/s/Christopher L. Dutton Christopher L. Dutton	President, Chief Executive Officer, and Director (principal executive officer)	March 14, 2006
/s/Mary G. Powell Mary G. Powell	Chief Operating Officer, Senior Vice President	March 14, 2006
/s/Robert J. Griffin Robert J. Griffin	Chief Financial Office, Vice President and Treasurer (principal financial officer and principal accounting officer)	March 14, 2006
*Nordahl L. Brue)	Chairman of the Board	
*Elizabeth A. Bankowski)		
*William H. Bruett)		
*Merrill O. Burns)		
*David R. Coates)	Directors	
*Kathleen C. Hoyt)		
*Euclid A. Irving)		
*Marc A. vanderHyeyden)		
*By: /s/Christopher L. Dutton Christopher L. Dutton (Attorney - in - Fact)		March 14, 2006

ITEM 15(a) 3 and Item 15c. Exhibits

Exhibit Number	Description	Exhibit	SEC Docket Incorporated By reference Or Page filed herewith
3.1	Amended and Restated Articles of Incorporation dated May 27, 2004	3A	Form 10-Q June 2004
3.c	By-laws of the Company, as amended December 8, 2003	3	Form 8-K Dec. 8 2003 (1-8291)
4.b.1	Indentures of First Mortgage and Deed of Trust dated as of February 1, 1955	4.b	2-27300
4.b.2	First Supplemental Indentures dated as of April 1, 1961	4.b.2	2-75293
4.b.3	Second Supplement Indenture dated as of January 1, 1966	4.b.3	2-75293
4.b.4	Third Supplemental Indenture dated as of July 1, 1968	4.b.4	2-75293
4.b.5	Fourth Supplemental Indenture dated as of October 1, 1969	5.b.5	2-75293
4.b.6	Fifth Supplemental Indenture dated as of December 1, 1973	4.b.6	2-75293
4.b.7	Seventh Supplemental Indenture dated as of August 1, 1976	4.b.7	2-99643
4.b.8	Eighth Supplement Indentures dated as of December 1, 1979	4.b.8	2-99643
4.b.9	Ninth Supplemental Indenture dated as of July 15, 1985	4.b.9	2-99643
4.b.10	Tenth Supplemental Indenture dated as of June 15, 1989	4.b.10	Form 10-K 1989 (1-8291)
4.b.11	Eleventh Supplemental Indenture dated as of September 1, 1990	4.b.11	Form 10-Q Sept. 1990 (1-8291)
4.b.12	Twelfth Supplemental Indenture dated as of March 1, 1992	4.b.12	Form 10-K 1991 (1-8291)
4.b.13	Thirteenth Supplemental Indenture dated as of March 1, 1992	4.b.13	Form 10-K 1991 (1-8291)
4.b.14	Fourteenth Supplemental Indenture dated as of November 1, 1993	4.b.14	Form 10-K 1993 (1-8291)
4.b.15	Fifteenth Supplemental Indenture dated as of November 1, 1993	4.b.15	Form 10-K 1993 (1-8291)
4.b.16	Sixteenth Supplemental Indenture dated as of December 1, 1995	4.b.16	Form 10-K 1995 (1-8291)
4.b.17	Revised form of Indenture as filed as an Exhibit to Registration Statement No. 33-59383	4.b.17	Form 10-Q Sept. 1995 (1-8291)
4.b.18	Credit Agreement by and among Green Mountain Power, The Bank of Nova Scotia, State Street Bank and Trust Company, Fleet National Bank, and Fleet National Bank, as Agent	4.b.18	Form 10-K 1997 (1-8291)
4.b.18(a)	Amendment to Exhibit 4.b.18	4.b.18(a)	Form 10-Q Sept. 1998 (1-8291)
4.b.19	Seventeenth Supplemental Indenture dated as of December 1, 2002	4.b.19	Form 10-K 2002 (1-8291)
10.a		10.a	33-8146

	Form of Insurance Policy issued by Pacific Insurance Company, with respect to indemnification of Directors and Officers.		
10.b.1	Firm Power Contract dated September 16, 1958, between the Company and the State of Vermont and supplements thereto dated September 19, 1958; November 15, 1958; October 1, 1960 and February 1, 1964	13.d	2-27300
10.b.2	Power Contract, dated February 1, 1968, between the Company and Vermont Yankee Nuclear Power Corporation	13.d	2-34346
10.b.3	Amendment, dated June 1, 1972, to Power Contract between the Company and Vermont Yankee Nuclear Power Corporation	13.f.1	2-49697
10.b.3(a)	Amendment, dated April 15, 1983, to Power Contract between the Company and Vermont Yankee Nuclear Power Corporation	10.b.3(a)	33-8164
10.b.3(b)	Additional Power Contract, dated February 1, 1984, between the Company and Vermont Yankee Nuclear Power Corporation	10.b.3(b)	33-8164
10.b.4	Capital Funds Agreement, dated February 1, 1968, between the Company and Vermont Yankee Nuclear Power Corporation	13.e	2-34346
10.b.5	Amendment, dated March 12, 1968, to Capital Funds Agreement between the Company and Vermont Yankee Nuclear Power Corporation	13.f	2-34346
10.b.6	Guarantee Agreement, dated November 5, 1981, of the Company for its proportionate share of the obligations of Vermont Yankee Nuclear Power Corporation under a $40 million loan arrangement	10.b.6	2-75293
10.b.7	Three-Party Power Agreement among the Company, VELCO and Central Vermont Public Service Corporation dated November 19, 1969	13.i	2-49697
10.b.8	Amendment to Exhibit 10.b.7, dated June 1, 1981	10.b.8	2-75293
10.b.9	Three-Party Transmission Agreement among the Company, VELCO and Central Vermont Public Service Corporation, dated November 21, 1969	10.b.9	2-49697
10.b.10	Amendment to Exhibit 10.b.9, dated June 1, 1981	10.b.10	2-75293

Exhibit Number	Description	Exhibit	SEC Docket Incorporated By reference Or Page filed Herewith
10.b.14	Agreement with Central Maine Power Company et al, to enter into joint ownership of Wyman plant, dated November 1, 1974	5.16	2-52900
10.b.15	New England Power Pool Agreement as amended to November 1, 1975	4.8	2-55385
10.b.16	Bulk Power Transmission Contract between the Company and VELCO dated June 1, 1968	13.v	2-49697
10.b.17	Amendment to Exhibit 10.b.16, dated June 1, 1970	13.v.i	2-49697
10.b.20	Power Sales Agreement, dated August 2, 1976, as amended October 1, 1977, and related Transmission Agreement, with the Massachusetts Municipal Wholesale Electric Company	10.b.20	33-8164
10.b.21	Agreement dated October 1, 1977, for Joint Ownership, Construction and Operation of the MMWEC Phase I Intermediate Units, dated October 1, 1977	10.b.21	33-8164
10.b.28	Contract dated February 1, 1980, providing for the sale of firm power and energy by the Power Authority of the State of New York to the Vermont Public Service Board	10.b.28	33-8164
10.b.30	Bulk Power Purchase Contract dated April 7, 1976, between VELCO and the Company	10.b.32	2-75293
10.b.33	Agreement amending New England Power Pool Agreement dated as of December 1, 1981, providing for use of transmission inter-connection between New England and Hydro Quebec	10.b.33	33-8164
10.b.34	Phase I Transmission Line Support Agreement dated as of December 1, 1981, and Amendment No. 1 dated as of June 1, 1982, between VETCO and participating New England utilities for construction, use and support of Vermont facilities of transmission interconnection between New England and Hydro Quebec	10.b.34	33-8164
10.b.35	Phase I Terminal Facility Support Agreement dated as of December 1, 1981, and Amendment No. 1 dated as of June 1, 1982, between New England Electric Transmission Corporation and participating New England utilities for construction, use and support of New Hampshire facilities of transmission interconnection between New England and Hydro Quebec	10.b.35	33-8164
10.b.36	Agreement with respect to use of Quebec Interconnection dated as of December 1, 1981, among participating New England utilities for use of transmission interconnection between New England and Hydro Quebec	10.b.36	33-8164
10.b.39	Vermont Participation Agreement for Quebec Interconnection dated as of July 15, 1982, between VELCO and participating Vermont utilities for allocation of VELCO's rights and obligations as a participating New England utility in the transmission interconnection between New England and Hydro Quebec.	10.b.39	33-8164

10.d.40	Vermont Electric Transmission Company, Inc. Capital Funds Agreement dated as of July 15, 1982, between VETCO and VELCO for VELCO to provide capital to VETCO for construction of the Vermont facilities of the transmission interconnection between New England and Hydro Quebec	10.b.40	33-8164
10.b.41	VETCO Capital Funds Support Agreement dated as of July 15, 1982, between VELCO and participating Vermont utilities for allocation of VELCO's obligation to VETCO under the Capital Funds Agreement	10.b.41	33-8164
10.b.42	Energy Banking Agreement dated March 21, 1983, among Hydro Quebec, VELCO, NEET and participating New England utilities acting by and through the NEPOOL Management Committee for terms of energy banking between participating New England utilities and Hydro Quebec	10.b.42	33-8164
10.b.43	Interconnection Agreement dated March 21, 1983, between Hydro Quebec and participating New England utilities acting by and through the NEPOOL Management Committee for terms and conditions of energy transmission between New England and Hydro Quebec	10.b.43	33-8164
10.b.44	Energy Contract dated March 21, 1983, between Hydro Quebec and participating New England utilities acting by and through the NEPOOL Management Committee for purchase of surplus energy from Hydro Quebec	10.b.44	33-8164
10.b.50	Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection, dated August 1, 1984, between certain electric distribution companies, including the Company	10.b.50	33-8164
10.b.51	Highgate Operating and Management Agreement, dated as of August 1, 1984, among VELCO and Vermont electric-utility companies, including the Company	10.b.51	33-8164

Exhibit Number	Description	Exhibit	SEC Docket Incorporated By reference Or Page filed Herewith
10.b.52	Allocation Contract for Hydro Quebec Firm Power dated July 25, 1984, between the State of Vermont and various Vermont electric utilities, including the Company	10.b.52	33-8164
10.b.53	Highgate Transmission Agreement dated as of August 1, 1984, between the Owners of the Project and various Vermont electric distribution companies	10.b.53	33-8164
10.b.61	Agreements entered in connection with Phase II of the NEPOOL/Hydro Quebec + 450 KV HVDC Transmission Interconnection	10.b.61	33-8164
10.b.62	Agreement between UNITIL Power Corp. and the Company to sell 23 MW capacity and energy from Stony Brook Intermediate Combined Cycle Unit	10.b.62	33-8164
10.b.68	Firm Power and Energy Contract dated December 4, 1987, between Hydro Quebec and participating Vermont utilities, including the Company, for the purchase of firm power for up to thirty years	10.b.68	Form 10-K 1992 (1-8291)
10.b.69	Firm Power Agreement dated as of October 26, 1987, between Ontario Hydro and Vermont Department of Public Service	10.b.69	Form 10-K 1992 (1-8291)
10.b.70	Firm Power and Energy Contract dated as of February 23, 1987, between the Vermont Joint Owners of the Highgate facilities and Hydro Quebec for up to 50 MW of capacity	10.b.70	Form 10-K 1992 (1-8291)
10.b.70(a)	Amendment to 10.b.70	10.b.70(a)	Form 10-K 1992 (1-8291)
10.b.71	Interconnection Agreement dated as of February 23, 1987, between the Vermont Joint Owners of the Highgate facilities and Hydro Quebec	10.b.71	Form 10-K 1992 (1-8291)
10.b.72	Participation Agreement dated as of April 1, 1988, between Hydro Quebec and participating Vermont utilities, including the Company, implementing the purchase of firm power for up to 30 years under the Firm Power and Energy Contract dated December 4, 1987 (previously filed with the Company's Annual Report on Form 10-K for 1987, Exhibit Number 10.b.68	10.b.72	Form 10-Q June 1988 (1-8291)
10.b.72(a)	Restatement of the Participation Agreement filed as Exhibit 10.b.72 on Form 10-Q for June 1988	10.b.72(a)	Form 10-K 1988 (1-8291)
10.b.77	Firm Power and Energy Contract dated December 29, 1988 between Hydro Quebec and participating Vermont utilities, including the Company, for the purchase of up to 54 MW of firm power and energy	10.b.77	Form 10-K 1988 (1-8291)
10.b.78	Transmission Agreement dated December 23, 1988, between the Company and Niagara Mohawk Power Corporation (Niagara Mohawk), for Niagara Mohawk to provide electric	10.b.78	Form 10-K 1988 (1-8291)

	transmission to the Company from Rochester Gas and Electric and Central Hudson Gas and Electric		
10.b.81	Sales Agreement dated May 24, 1989, between the Town of Hardwick, Hardwick Electric Department and the Company for the Company to purchase all of the output of Hardwick's generation and transmission sources and to provide Hardwick with all-requirements energy and capacity except for that provided by the Vermont Department of Public Service or Federal Preference Power	10.b.81	Form 10-Q June 1989 (1-8291)
10.b.82	Sales Agreement dated July 14, 1989, between Northfield Electric Department and the Company for the Company to purchase all of the output of Northfield's generation and transmission sources and to provide Northfield with all-requirements energy and capacity except for that provided by the Vermont Department of Public Service or Federal Preference Power	10.b.82	Form 10-Q June 1989 (1-8291)
10.b.85	Power Purchase and Sale Agreement between Morgan Stanley Capital Group Inc. and the Company.	10.b.85	Form 10-K 1998 (1-8291)
10.b.90	Power Purchase Agreement between Entergy Nuclear Vermont Yankee LLC and Vermont Yankee Nuclear Power Corporation	10.b.90	Form 10-Q June 2002 (1-8291)
10.b.91	First Amendment to Purchase Power Agreement listed as Exhibit Number 10.b.90, between Entergy Nuclear Vermont Yankee LLC and Vermont Yankee Nuclear Power Corporation	10.b.91	Form 10-Q June 2002 (1-8291)
10.b.92	Amendment to Power Purchase and Sale Agreement between Morgan Stanley Capital Group, Inc. and the Company	10.b.92	Form 10-K 2002 (1-8291)
10.b.93	2001 Amendatory Agreement - Power Supply Agreement between the Company and Vermont Yankee Nuclear Power Corporation	10.b.93	Form 10-K 2004

	Management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K to Item 14(c)., all under SEC Docket 1-8291		
10.d.1b	Green Mountain Power Corporation Second Amended and Restated Deferred Compensation Plan for Directors	10.d.1b	Form 10-K 1993
10.d.1c	Green Mountain Power Corporation Second Amended and Restated Deferred Compensation Plan for Officers	10.d.1c	Form 10-K 1993
10.d.1d	Amendment No. 93.1 to the Amended and Restated Deferred Compensation Plan for Officers	10.d.1d	Form 10-K 1993
10.d.1e	Amendment No. 94.1 to the Amended and Restated Deferred Compensation Plan for Officers	10.d.1e	Form 10-Q June 1994
10.d.2	Green Mountain Power Corporation Medical Expense Reimbursement Plan	10.d.2	Form 10-K 1991
10.d.4	Green Mountain Power Corporation Officers’ Insurance Plan	10.d.4	Form 10-K 1991
10.d.4a	Green Mountain Power Corporation Officers' Insurance Plan as amended	10.d.4a	Form 10-K 1990
10.d.8	Green Mountain Power Corporation Officers' Supplemental Retirement Plan	10.d.8	Form 10-K 1990
10.d.15c	Green Mountain Power 2000 Stock Incentive Plan	10.d.15c	Form 10-K 2001
10.d.40	Change in Control Agreement with C. L. Dutton	10.d.40	Form 10-K 2003
10.d.41	Change in Control Agreement with D. J. Rendall, Jr.	10.d.41	Form 10-K 2003
10.d.42	Change in Control Agreement with R. J. Griffin	10.d.42	Form 10-K 2003
10.d.43	Change in Control Agreement with W. S. Oakes	10.d.43	Form 10-K 2003
10.d.44	Change in Control Agreement with M. G. Powell	10.d.44	Form 10-K 2003
10.d.45	Change in Control Agreement with R. E. Rogan	10.d.45	Form 10-K 2005
10.d.46	Deferred Stock Unit Agreement with D. J. Rendall, Jr.	10.d.46	Form 10-K 2003
10.d.47	Deferred Stock Unit Agreement with C. L. Dutton	10.d.47	Form 10-K 2003
10.d.48	Deferred Stock Unit Agreement with S. C. Terry	10.d.48	Form 10-K 2003
10.d.49	Deferred Stock Unit Agreement with R. J. Griffin	10.d.49	Form 10-K 2003
10.d.50	Deferred Stock Unit Agreement with W. S. Oakes	10.d.50	Form 10-K 2003
10.d.51	Deferred Stock Unit Agreement with M. G. Powell	10.d.51	Form 10-K 2003
10.d.52	Deferred Stock Unit Agreement with E. A. Bankowski	10.d.52	Form 10-K 2003
10.d.53	Deferred Stock Unit Agreement with N. L. Brue	10.d.53	Form 10-K 2003
10.d.54	Deferred Stock Unit Agreement with W. H. Bruett	10.d.54	Form 10-K 2003

10.d.55	Deferred Stock Unit Agreement with M. O. Burns	10.d.55	Form 10-K 2003
10.d.56	Deferred Stock Unit Agreement with D. R. Coates	10.d.56	Form 10-K 2003
10.d.57	Deferred Stock Unit Agreement with E. A. Irving	10.d.57	Form 10-K 2003
10.d.58	Director Deferral Agreement with E. A. Bankowski	10.d.58	Form 10-K 2003
10.d.59	Director Deferral Agreement with M. O. Burns	10.d.59	Form 10-K 2003
10.d.60	Director Deferral Agreement with D. R. Coates	10.d.60	Form 10-K 2003
10.d.61	Director Deferral Agreement with E. A. Irving	10.d.61	Form 10-K 2003
10.d.62	Deferred Stock Unit Agreement with E. A. Bankowski	10.d.62	Form 10-Q June 2004
10.d.63	Deferred Stock Unit Agreement with N. L. Brue	10.d.63	Form 10-Q June 2004
10.d.64	Deferred Stock Unit Agreement with W. H. Bruett	10.d.64	Form 10-Q June 2004
10.d.65	Deferred Stock Unit Agreement with M. O. Burns	10.d.65	Form 10-Q June 2004
10.d.66	Deferred Stock Unit Agreement with D. R. Coates	10.d.66	Form 10-Q June 2004
10.d.67	Deferred Stock Unit Agreement with K. C. Hoyt	10.d.67	Form 10-Q June 2004
10.d.68	Deferred Stock Unit Agreement with E. A. Irving	10.d.68	Form 10-Q June 2004
10.d.69	Deferred Stock Unit Agreement with M. A. vanderHeyden	10.d.69	Form 10-Q June 2004
10.d.70	Director Deferral Agreement with E. A. Bankowski	10.d.70	Form 8-K Dec. 2, 2004
10.d.71	Director Deferral Agreement with M. O. Burns	10.d.71	Form 8-K Dec. 2, 2004
10.d.72	Director Deferral Agreement with E. A. Irving	10.d.72	Form 8-K Dec. 2, 2004
10.d.73	Officer Deferral Agreement with S. C. Terry	10.d.73	Form 8-K Dec. 2, 2004
10.d.74	Officer Deferral Agreement with W. S. Oakes	10.d.74	Form 8-K Dec. 2, 2004
10.d.75	Board of Directors' Resolutions Amending Deferred Compensation Plan	10.d.75	Form 8-K Dec. 30, 2004
10.d.76	Officer Compensation Table	10.d.76	Form 10-K 2005
10.d.77	2006 Management Compensation Plan Description	10.d.77	Form 10-K 2005

	Management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K to Item 14(c)., all under SEC Docket 1-8291		
10.d.79	Green Mountain Power Corporations New Supplemental Retirement Plan with C. L. Dutton	10.d.79	Form 8-K 2005 July 29, 2005
10.d.80	Green Mountain Power Corporations New Supplemental Retirement Plan with R. J. Griffin	10.d.80	Form 8-K 2005 July 29, 2005
10.d.81	Green Mountain Power Corporations New Supplemental Retirement Plan with W. S. Oakes	10.d.81	Form 8-K 2005 July 29, 2005
10.d.82	Green Mountain Power Corporations New Supplemental Retirement Plan with M. G. Powell	10.d.82	Form 8-K 2005 July 29, 2005
10.d.83	Green Mountain Power Corporations New Supplemental Retirement Plan with D. J. Rendall, Jr.	10.d.83	Form 8-K 2005 July 29, 2005
10.d.84	Green Mountain Power Corporations Officers' Supplemental Retirement Plan with S. C. Terry	10.d.84	Form 10-K 2004
10.d.85	Green Mountain Power Corporations New Supplemental Retirement Plan with R. E. Rogan	10.d.85	Form 10-K 2005
10.d.86	Green Mountain Power Corporation 2004 Stock Incentive Plan	10.d.86	Form 10-K 2005
10.d.87	Green Mountain Power Corporation Third Amended and Restated Deferred Compensation Plan for Certain Officers	10.d.87	Form 10-K 2004
10.d.88	2005 Officer Deferred Stock Unit Agreement with Christopher L. Dutton	10.d.88	Form 8-K May 27, 2005
10.d.89	2005 Officer Deferred Stock Unit Agreement with Robert J. Griffin	10.d.89	Form 8-K May 27, 2005
10.d.90	2005 Officer Deferred Stock Unit Agreement with Walter S. Oakes	10.d.90	Form 8-K May 27, 2005
10.d.91	2005 Officer Deferred Stock Unit Agreement with Mary G. Powell	10.d.91	Form 8-K May 27, 2005
10.d.92	2005 Officer Deferred Stock Unit Agreement with Donald J. Rendall, Jr.	10.d.92	Form 8-K May 27, 2005
10.d.93	2005 Officer Deferred Stock Unit Agreement with Stephen C. Terry	10.d.93	Form 8-K May 27, 2005
10.d.94	Officer Deferred Stock Unit Agreement with Stephen C. Terry	10.d.94	Form 8-K May 27, 2005
10.d.95	2005 Supplemental Retirement Plan with Stephen C. Terry	10.d.95	Form 8-K May 27, 2005
10.d.96	2005 Director Deferred Stock Unit Agreement with Elizabeth A. Bankowski	10.d.96	Form 8-K July 26, 2005
10.d.97	2005 Director Deferred Stock Unit Agreement with Nordahl L. Brue	10.d.97	Form 8-K July 26, 2005
10.d.98	2005 Director Deferred Stock Unit Agreement with William H. Bruett	10.d.98	Form 8-K July 26, 2005
10.d.99	2005 Director Deferred Stock Unit Agreement with Merrill O. Burns	10.d.99	Form 8-K July 26, 2005
10.d.100	2005 Director Deferred Stock Unit Agreement with David R. Coates	10.d.100	Form 8-K July 26, 2005
10.d.101	2005 Director Deferred Stock Unit Agreement with Kathleen C. Hoyt	10.d.101	Form 8-K July 26, 2005
10.d.102		10.d.102	Form 8-K

	2005 Director Deferred Stock Unit Agreement with Euclid A. Irving		July 26, 2005
10.d.103	2005 Director Deferred Stock Unit Agreement with Marc A. vanderHeyden	10.d.103	Form 8-K July 26, 2005
10.d.104	Director Deferral Agreement with David R. Coates	10.d.104	Form 8-K January 4, 2006
14	Green Mountain Power Corporation's Code of Ethics and Conduct dated October 6, 2003	14	Form 10-K 2004
23.1	Consent of Deloitte and Touche LLP	23.1	
24	Limited Power of Attorney	24	
31.1	Certification of Christopher L. Dutton, President and Chief Executive Officer, pursuant to Rules 13a-14(a) and Rule 15d-14(a) promulgated under the Securities Act of 1934, as Adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	31.1	Form 10-K 2005
31.2	Certification of Robert J. Griffin, Chief Financial Officer, Vice President and Treasurer pursuant to Rules 13a-14(a) and Rule 15d-14(a) promulgated under the Securities Act of 1934, as Adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	31.2	Form 10-K 2005
32.1	Certification of Christopher L. Dutton, President and Chief Executive Officer, Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	32.1	Form 10-K 2005
32.2	Certification of Robert J. Griffin, Chief Financial Officer, Vice President and Treasurer Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	32.2	Form 10-K 2005