NYSE Euronext
Form 4
April 06, 2009

FORM 4

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

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

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL

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(Print or Type Responses)

1. Name and Address of Reporting Person *
MCFARLAND DUNCAN M

(Last) (First) (Middle)

C/O NYSE EURONEXT, 11 WALL STREET

(Street)

NEW YORK, NY 10005

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
NYSE Euronext [NYX]

3. Date of Earliest Transaction (Month/Day/Year)
04/02/2009

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

__X__ Director _____ 10% Owner
_____ Officer (give title below) _____ Other (specify below)

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security	2. Conversion or Exercise	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any	4. Transaction Code	5. Number of Derivative Securities	6. Date Exercisable and Expiration Date (Month/Day/Year)	7. Title and Amount of Underlying Securities (Instr. 3 and 4)	8. Pr Deriv Secu

(Instr. 3)	Price of Derivative Security		(Month/Day/Year)	(Instr. 8)		Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)						(Instr
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares	
Restricted Stock Units	(1)	04/02/2009 (2)		A		4,078		(1)	(1)	Common Stock, par value $0.01 per share	4,078	$

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
MCFARLAND DUNCAN M C/O NYSE EURONEXT 11 WALL STREET NEW YORK, NY 10005	X			

Signatures

Janet M. Kissane under POA dated April 5, 2007	04/03/2009
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) RSUs awarded under the NYSE Euronext 2008 Omnibus Incentive Plan. Each RSU represents the right to receive one share of the Issuer's common stock upon the Reporting Person's termination of service on the Board of Directors for any reason other than termination for cause.

(2) Pursuant to resolutions of the Issuer's Board of Directors adopted April 2, 2009. The amount of the award was determined in part by reference to the closing price of the Issuer's common stock on April 1, 2009.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. This rate of increase gradually declines to 5.5 percent in 2009. 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, 2003 by $4.8 million and the total of the service and interest cost components of net periodic postretirement cost for the year ended December 31, 2003 by $434,000. Decreasing the trend rate by one percentage point for all future years would decrease the accumulated postretirement benefit obligation at December 31, 2003 by $3.8 million, and the total of the service and interest cost components of net periodic postretirement cost for 2003 by $339,000. The Company's defined benefit plan investment policy seeks to achieve sufficient growth to enable the pension plan to meet its future obligations and to maintain certain funded ratios and minimize near-term

cost volatility. Current guidelines specify generally that 65 percent of plan assets be invested in equity securities, 30 percent of 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. Pension Assets Weighted Average Asset Allocation For the years ended December 31, 2004 TARGET 2003 2002 ----------- ------- ------- Asset Category Equity Securities . . . 65.00% 63.10% 59.61% Debt Securities . . . . 30.00% 24.92% 31.65% Real Estate . . . . . . 0.00% 0.00% 0.00% Other . . . . 0.00% 6.60% 8.74% Alternative investments 5.00% 5.38% 0.00% ----------- ------- ------- total . . . . 100.00% 100.00% 100.00% =========== ======= ======= I. COMMITMENTS AND CONTINGENCIES 1. INDUSTRY RESTRUCTURING. The electric utility business is being subjected to rapidly increasing competitive pressures stemming from a combination of trends. Certain states, including all the New England states except Vermont, have enacted legislation to allow retail customers to choose their electric suppliers, with incumbent utilities required to deliver that electricity over their transmission and distribution systems. Recent power supply management difficulties in some regulatory jurisdictions, such as California, have dampened any immediate push towards deregulation in Vermont. Legislation has been introduced in the Vermont legislature that would permit (but not require) the Company to negotiate with individual customers to permit such customers to procure their own electric power supply requirements, subject to VPSB approval. We cannot predict whether this legislation will be enacted. If enacted, the Company would not negotiate any such arrangement unless in the Company's estimation, the arrangement assured the Company of full recovery of any resulting stranded costs and that the Company's financial condition would not otherwise be adversely affected. Alternative forms of performance-based regulation currently appear as possible intermediate steps towards deregulation. There can be no assurance that any potential future restructuring plan ordered by the VPSB, the courts, or through legislation will include a mechanism that would allow for full recovery of our stranded costs and include a fair return on those costs as they are being recovered. 2. 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. In 2003, the Company expended $2.6 million to cover its obligations under the consent decree and we have estimated total future costs of the Company's net future obligations through 2033 under the consent decree to be $8.5 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 also recorded a regulatory asset of $13.0 million to reflect future recovery of these costs, as well as past unrecovered costs. Pursuant to the Company's 2003 Rate Plan, as approved by the VPSB, the Company will begin to amortize past unrecovered costs in 2005. The Company will amortize the full amount of these costs, as they are incurred, over 20 years without a return. The amortization will 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. 3. JOINTLY-OWNED FACILITIES. The Company has joint-ownership interests in electric generating and transmission facilities at December 31, 2003, as follows: Share of Share of Ownership Share of Utility Accumulated Interest Capacity Plant Depreciation --------- --------- -------------- ------------ (In %) (In MWh) (In thousands) Highgate . . . . 33.8 67.6 $ 10,296 $ 4,926 McNeil . . . . 11.0 5.9 8,989 5,379 Stony Brook (No. 1). . . 8.8 31 10,377 8,965 Wyman (No. 4). . . . . . 1.1 6.8 1,980 1,380 Metallic Neutral Return. 59.4 - 1,563 806 Metallic Neutral Return is a neutral conductor for NEPOOL/Hydro-Quebec Interconnection The Company's share of expenses for these facilities is reflected in the Consolidated Statements of Income. Each participant in these facilities must provide its own financing. 4. RATE MATTERS. RETAIL RATE CASES - On

December 22, 2003, the VPSB approved a three-year rate plan (the "2003 Rate Plan") jointly proposed earlier in the year by the Company and the Department. The 2003 Rate Plan, as approved, covers the period through 2006 and includes the following principal elements. The Company's rates will remain 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, if the increases are supported by cost of service schedules submitted 60 days prior to the effective dates. If the Company's cost of service filings in 2005 or 2006 establish that a lesser rate increase in required for the Company to meet its revenue requirements, the Company will implement the lesser rate increase. The Company may seek additional rate increases 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 reduced from 11.25 percent to 10.5 percent, for the period January 1, 2003 through December 31, 2006. During the same period, the Company's earnings on core utility operations are capped at 10.5 percent. If excess earnings result in 2004, they will be applied to reduce regulatory assets. 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 will carry forward into 2004 $3.0 million in deferred revenue remaining at December 31, 2003 from the Company's 2001 rate case settlement summarized below. The Company will 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 amortizations to be allowed in future rates. Pine Street costs will be recovered over a twenty-year period without a return. The Company will file with the VPSB in early 2004 a new fully allocated cost of service study and rate re-design, which will allocate the Company's revenue requirement among all customer classes on the basis of current costs. The new rate design will be subject to VPSB approval. 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. The target for filing such a plan is April 2004. If the Company and Department agree on such a plan, and it is approved by the VPSB, the alternative regulation plan would supersede the 2003 Rate Plan. In January 2001, the VPSB approved a rate case settlement between the Company and the Department (the "2001 Settlement Order"). The final settlement, as approved, included the following: * The Company received a rate increase of 3.42 percent above existing rates, beginning with bills rendered January 23, 2001, and prior temporary rate increases became permanent; * Rates were set at levels that recover the Company's Hydro-Quebec Vermont Joint Owners ("VJO") contract costs, effectively ending the regulatory disallowances experienced by the Company from 1998 through 2000; * The Company agreed not to seek any further increase in electric rates prior to April 2002 (effective in bills rendered January 2003) unless certain substantially adverse conditions arise, including a provision allowing a request for additional rate relief if power supply costs increase in excess of $3.75 million over forecasted levels; * The Company agreed to write off in 2000 approximately $3.2 million in unrecovered rate case litigation costs, and to freeze its dividend rate until it successfully replaces short-term credit facilities with long-term debt or equity financing; * Seasonal rates were eliminated in April 2001, which generated approximately $8.5 million in additional cash flow in 2001 that can be utilized to offset increased costs during 2002 and 2003; * The Company agreed to consult extensively with the Department regarding capital spending commitments for upgrading our electric distribution system and to adopt customer care and reliability performance standards, in a first step toward possible development of performance-based rate-making; * The Company agreed to withdraw its Vermont Supreme Court appeal of the VPSB's Order in the 1997 rate case; and * The Company agreed to an earnings limitation for its electric operations in an amount equal to its allowed rate of return of 11.25 percent, with amounts earned over the limit being used to write off regulatory assets. On January 23, 2001, the VPSB approved the Company's settlement with the Department, with two additional conditions: * 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 is restricted. The Company earned approximately $30,000 in excess of its allowed rate of return during 2001 before writing off regulatory assets in the same amount. The Company earned approximately $4.4 million less than its allowed rate of return during 2002 before recognition of deferred revenues in the same amount. 5. DEFERRED CHARGES NOT INCLUDED IN RATE BASE. The Company has incurred and deferred approximately $11.1 million in costs for Pine Street, tree trimming, storm damage, and regulatory commission work of which approximately $408,000 is being amortized on an annual basis. Currently, the Company amortizes such costs based on amounts being recovered and does not receive a return on amounts deferred. Management expects to recover these costs over periods ranging from five to twenty years beginning January 1, 2005, pursuant to the 2003 Rate Plan. The 2001 Settlement Order requires the remaining balance and future expenditures of deferred regulatory commission charges be amortized over seven years. 6. COMPETITION. During 2001, the Town of Rockingham (Rockingham), Vermont initiated inquiries and legal procedures to establish its own electric utility, seeking to purchase the Bellows Falls hydroelectric facility from a third party, and the associated distribution plant owned by the Company within the town. In March 2002, voters in Rockingham approved an article authorizing Rockingham to create a municipal utility by acting to acquire a municipal plant, which would include the electric distribution systems of the Company and/or Central Vermont Public Service Corporation. In November 2003, Rockingham notified the Company that the town intended to initiate proceedings before the town selectboard to condemn the Company's distribution and associated property located within the town. The Company sought and obtained in December 2003 a preliminary injunction from the State Superior Court prohibiting the town from proceeding with condemnation before the selectboard. The Company successfully argued that Vermont law required Rockingham to pursue any such municipalization effort by petition to the VPSB, which is required to determine both the fair value of any assets subject to municipalization and the amount of damages to the utility caused by severance of the property subject to municipalization. The preliminary injunction remains in effect and Rockingham has not filed any petition with the VPSB seeking to municipalize assets. The Company receives annual revenues of approximately $4.0 million from its customers in Rockingham. Should Rockingham create a municipal system, the Company would vigorously pursue its right to receive just compensation from Rockingham. Such compensation would include full reimbursement for Company assets, if acquired, and full reimbursement of any other costs associated with the loss of customers in Rockingham, to assure that neither our remaining customers nor our shareholders effectively subsidize a Rockingham municipal utility. 7. 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, complaining 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 has petitioned the VPSB to make additional dam improvements at the facility at an estimated cost of $350,000. The VPSB must approve the Company's petition before the proposed improvements can be implemented. This regulatory proceeding is pending and the Company is unable to predict whether the Company's petition will be approved or whether the VPSB will impose regulatory conditions or penalties in connection with this proceeding. The Company is involved in other legal and administrative proceedings in the normal course of business and does not believe that the ultimate outcome of these proceedings will have a material effect on the financial position or the results of operations of the Company. J. OBLIGATIONS UNDER TRANSMISSION INTERCONNECTION SUPPORT AGREEMENT 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 expands the Phase I facilities from 690 megawatts to 2,000 megawatts and provides for transmission of Hydro-Quebec power from the Phase I terminal in northern New Hampshire 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, 2003, the present value of the Company's obligation is approximately $4.6 million. Projected future minimum payments under the Phase II support agreements are as follows: Year ending December 31 -------------- (In thousands) 2004. . . . . $ 387 2005. . . . . 387 2006. . . . . 387 2007. . . . . 387 2008. . . . . 387 Total for 2009-2015 2,712 Total . . . . . $ 4,647 ============== 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. K. LONG-TERM POWER PURCHASES 1. 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 "Power Supply Expenses" 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 significant purchased power contracts of this type in effect during 2003 follows: STONY BROOK ---------------------- (Dollars in thousands) Plant capacity 352.0 MW Company's share of output 4.40% Contract period expires: 2006 Company's annual share of: Interest $ 128 Other debt service 444 Other capacity 535 Total annual capacity $ 1,107 ====================== Company's share of long-term debt $ 1,817 2. VERMONT YANKEE The Company has a long-term power purchase contract with VY, 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 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 VY sale of its nuclear power plant to ENVY also calls for ENVY, through its power contract with VY, 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, including projected charges for the years indicated, follows: Vermont Yankee Contract ---------- (Dollars in thousands except per KWh) Capacity acquired 106 MW Contract period expires 2012 Company's share of output 20% Annual energy charge 2003 $ 37,288 estimated 2004-2015 $ 32,377 Average cost per KWh 2003 $ 0.042 estimated 2004-2015 $ 0.042 Payments totaling $0.5 million were made in 2002 to VY's non-Vermont sponsors in return for guarantees those sponsors made to ENVY to finalize the VY sale. The Company received its share of the VY power plant sale proceeds, approximately $8.2 million, during October 2003, and used the proceeds to retire debt. 3. 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 "1987 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 1987 Contract participant fails to meet its obligation under the 1987 Contract with Hydro-Quebec, the remaining contract participants, including the Company, will step-up to the defaulting participant's share on a prorated basis. Hydro-Quebec also has the right to reduce the load factor from 75 percent to 65 percent under the 1987 Contract a total of three times over the life of the contract. The Company can delay such reduction by one year under the 1987 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 Company estimates that 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, and we expect Hydro-Quebec to exercise its third option in 2004 for deliveries occurring principally during 2005. 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 1987 Contract, Vermont joint owners, including the Company, have two remaining options to adjust deliveries by a five percent load factor. These cannot be used to offset Hydro-Quebec's reductions through 2005, but may be used after 2005 to manage power supply costs. All of 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. A summary of the Hydro-Quebec contracts, including historic and projected charges for the years indicated, follows: THE 1987 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 65%-75% 65%-75%

(annual load factor) Annual energy charge 2003 $ 10,565 $ 7,219 estimated 2004-2015 13,756 (1) 9,400 (1) Annual capacity charge 2003 $ 16,857 $ 11,519 estimated 2004-2015 $ 17,122 (1) $ 11,699 (1) Average cost per KWh 2003 $ 0.071 $ 0.071 estimated 2004-2015 $ 0.064 (2) $ 0.064 (2) (1)Estimated average includes load factor reduction to 65 percent in 2004 (2)Estimated average in nominal dollars levelized over the period indicated includes amortization of payments to Hydro-Quebec Under a separate arrangement established in December 1997 (the "9701 arrangement"), 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 1987 Contract. The cumulative amount of energy purchased under the 9701 arrangement shall not exceed 950,000 MWh. Hydro-Quebec's option to curtail energy deliveries pursuant to the 1987 Contract may be exercised in addition to these purchase options. Over the same period, Hydro-Quebec can exercise an option on an annual basis to purchase a total of 600,000 MWh ("option B") at the 1987 Contract energy price. Hydro-Quebec can purchase no more than 200,000 MWh in any given contract year ending October 31. As of December 31, 2003, Hydro-Quebec had purchased or called to purchase 513,000 MWh under option B. In 2003, Hydro-Quebec exercised option A and option B, and called for delivery to third parties at a net expense to the Company of approximately $4.5 million, including capacity charges. In 2002, Hydro-Quebec exercised option A and called for deliveries to third parties at a net expense to the Company of approximately $3.0 million, including capacity charges. In 2001, Hydro-Quebec exercised option A and option B, and called for deliveries to third parties at a net expense to the Company of approximately $6.5 million, including capacity charges. The Company believes that it is probable that Hydro-Quebec will call options A and B for 2004, and has purchased replacement power at an incremental cost of $3.2 million. The Company has also covered 54 percent of expected calls during 2005 at an incremental cost of $1.1 million. 4. MORGAN STANLEY CONTRACT In February 1999, the Company entered into a contract with MS. In August 2002, the MS contract was modified and extended to December 31, 2006. The contract provides the Company a means of managing price risks associated with changing fossil fuel prices. On a daily basis, and at MS's discretion, the Company will sell power to MS from either (i) all or part of our portfolio of power resources at predefined operating and pricing parameters or (ii) any power resources available to the Company, provided that sales of power from sources other than Company-owned generation comply with the predefined operating and pricing parameters. MS then sells to us, at a predefined price, power sufficient to serve pre-established load requirements. MS is also responsible for scheduling supply resources. The Company remains responsible for resource performance and availability. MS provides no coverage against major unscheduled outages. Beginning January 1, 2004, the Company will reduce the power that it sells to MS. The reduction in sales is expected to reduce wholesale revenues by approximately $65 million, and power supply expense by a similar amount. The Company does not expect the change to adversely affect its opportunity to earn its allowed rate of return during 2004. The Company and MS have agreed to the protocols that are used to schedule power sales and purchases and to secure necessary transmission. The MS contract is a derivative that includes a risk premium above expected future costs of electricity. L. DISCONTINUED OPERATIONS. The Company has sold or otherwise disposed of a significant portion of the operations and assets of NWR, which owned and invested in energy generation, energy efficiency, and wastewater treatment projects. The net reserve for loss from discontinued operations reflects management's current estimate. The residual operations earned $0.01 per share in 2003 and $0.02 per share in 2002, primarily as a result of adjustments to a reserve for warranty claims. At December 31, 2003, assets remaining include a wind power partnership investment, a note receivable from a regional hydro-power project, and notes receivable and equity investments with two wastewater treatment projects, one of which has risk factors that include the outcome of warranty litigation, and future cash requirements necessary to minimize costs of winding down wastewater operations. Several municipalities using wastewater treatment equipment have commenced or threatened litigation against NWR. The ultimate loss remains subject to the disposition of remaining assets and liabilities, and could exceed the amounts recorded. The following illustrates the results and financial statement impact of discontinued operations during and at the periods shown: 2003 2002 2001 ------------------------------- ------ ------- (In thousands except per share) Revenues . . . . $ - $ 88 $ 156 ------------------------------- ------ ------- Gain (loss) on disposal. . . . . . 79 99 (182) Net income (loss). . . . . $ 79 $ 99 $ (182) =============================== ====== ======= Net income (loss) per share-basic. $ 0.01 $ 0.02 $(0.03) Proceeds from asset sales. . . . . $ - $ - $ - Total assets . . . . $ 1,488 $1,622 $2,700 State income taxes . . . . $ 12 $ 19 $ (175) Federal income taxes 39 52 (550)

Investment tax credits . . . . . . - - - ------------------------------ ------ ------- Income tax expense (benefit) . . . $ 51 $ 71 $ (725) ================================ ====== ======= M. 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. 2003 Quarter ended MARCH JUNE SEPTEMBER DECEMBER TOTAL -------- -------- ---------- --------- -------- (Amounts in thousands except per share data) 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. 5,118 5,129 5,141 5,165 5,140 shares outstanding 2002 Quarter ended MARCH JUNE SEPTEMBER DECEMBER TOTAL ------- ------- ---------- --------- -------- (Amounts in thousands except per share data) Operating revenues . . . . $68,866 $65,135 $ 73,477 $ 67,130 $274,608 Operating income . . . . 4,441 2,814 3,745 4,080 15,080 Net income-continuing operations . . . . $ 3,354 $ 1,875 $ 3,042 $ 3,028 $ 11,299 Net income-discontinued operations . . . . . . - - - 99 99 Net Income applicable to common stock. . . . . $ 3,354 $ 1,875 $ 3,042 $ 3,127 $ 11,398 ======= ======= ========== ========= ======== Basic earnings per share from: Continuing operations. . . . . $ 0.59 $ 0.33 $ 0.53 0.57 $ 2.02 Discontinued operations. . . . . - - - 0.02 0.02 Basic earnings per share . . . . $ 0.59 $ 0.33 $ 0.53 $ 0.59 $ 2.04 ======= ======= ========== ========= ======== Weighted average common shares outstanding . . 5,691 5,711 5,723 5,333 5,756 Diluted earnings per share from: Continuing operations. . . . . $ 0.57 $ 0.32 $ 0.52 0.55 $ 1.96 Discontinued operations. . . . . - - - 0.02 0.02 Diluted earnings per share . . . . $ 0.57 $ 0.32 $ 0.52 $ 0.57 $ 1.98 ======= ======= ========== ========= ======== Weighted average common and common equivalent. 5,870 5,877 5,879 5,497 5,756 shares outstanding 2001 Quarter ended MARCH JUNE SEPTEMBER DECEMBER TOTAL ------- -------- ---------- ---------- --------- (Amounts in thousands except per share data) Operating revenues . . . . $74,796 $67,471 $ 76,051 $ 65,146 $283,464 Operating income . . . . 4,575 4,275 4,573 3,036 16,459 Net income-continuing operations . . . . $ 2,914 $ 2,884 $ 3,387 $ 1,675 $ 10,860 Net loss-discontinued operations . . . . - (150) - (32) (182) Net Income applicable to common stock. . . . . $ 2,914 $ 2,734 $ 3,387 $ 1,643 $ 10,678 ======= ======== ========== ========== ========= Basic earnings (loss) per share from: Continuing operations. . . . . $ 0.52 $ 0.52 $ 0.60 $ 0.29 $ 1.93 Discontinued operations. . . . . - (0.03) - - (0.03) Basic earnings per share . . . . $ 0.52 $ 0.49 $ 0.60 $ 0.29 $ 1.90 ======= ======== ========== ========== ========= Weighted average common shares outstanding . . 5,588 5,615 5,644 5,672 5,630 Diluted earnings (loss) per share from: Continuing operations. . . . . $ 0.51 $ 0.50 $ 0.58 $ 0.29 $ 1.88 Discontinued operations. . . . . - (0.03) - - (0.03) Diluted earnings (loss) per share: . . . . . . $ 0.51 $ 0.47 $ 0.58 $ 0.29 $ 1.85 ======= ======== ========== ========== ========= Weighted average common and common equivalent. 5,741 5,777 5,814 5,848 - shares outstanding Independent Auditors' Report To the Board of Directors of Green Mountain Power Corporation: We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Green Mountain Power Corporation and subsidiaries (the Company) as of December 31, 2003, and 2002, and the related consolidated statements of income, comprehensive income, changes in stockholders equity and cash flows for each of the two years in the period ended December 31, 2003. The financial statements of Green Mountain Power Corporation and subsidiaries as of December 31, 2001 and for the year then ended were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion which included an emphasis of matter paragraph on those financial statements in their report dated March 12, 2002. 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 audit. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion. In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Green Mountain Power Corporation and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the two years then ended in conformity with accounting principles generally accepted in the United States. Deloitte & Touche, LLP /s/Deloitte & Touche, LLP Boston, Massachusetts February 25, 2004 Report of Independent Public Accountants To the Board of Directors of Green Mountain Power Corporation: We have audited the accompanying consolidated balance sheets and consolidated capitalization data of Green Mountain Power Corporation (a Vermont corporation) and its subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion. In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Green Mountain Power Corporation and its subsidiaries as of December 31, 2001 and 2000, and the consolidated results of its operations and cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States. As discussed in Note A to the financial statements, effective January 1, 2001, the company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. /s/ Arthur Andersen LLP Boston, Massachusetts March 12, 2002 The above report of Arthur Andersen LLP is a copy of the previously issued report, and the report has not been reissued by Arthur Andersen LLP. Schedule II GREEN MOUNTAIN POWER CORPORATION VALUATION AND QUALIFYING ACCOUNTS AND RESERVES For the Years Ended December 31, 2003, 2002, and 2001 Balance at Additions Additions Balance at Beginning of Charged to Charged to End of Period Cost & Expenses Other Accounts Deductions Period ----------- ---------------- -------------- ---------- ----------- Injuries and Damages (1) -- 2003 . . . . $10,489,506 (521,493) - 1,522,330 $ 8,445,683 2002 . . . . 12,064,548 325,000 134,505 2,034,547 10,489,506 2001 . . . . 13,382,713 212,555 312,229 1,842,949 12,064,548 Allowance for Doubtful Accounts -- 2003 . . . . 547,316 143,214 - - 690,530 2002 . . . . 575,890 - 37,270 65,844 547,316 2001 . . . . 425,890 150,000 575,890 (1) Includes Pine Street Barge Canal reserves INDEPENDENT AUDITORS' REPORT To the Board of Directors and Stockholders of Green Mountain Power Corporation Colchester, VT We have audited the financial statements of Green Mountain Power Corporation as of December 31, 2003 and 2002 and for each of the two years in the period ended December 31, 2003, and have issued our report thereon dated February 25, 2004; such report is included elsewhere in this Form 10-K. Our audit also included the 2003 and 2002 information included in the financial statement schedule of Green Mountain Power Corporation, listed in Item 8. This financial statement schedule is the responsibility of the Corporation's management. Our responsibility is to express an opinion based on our audits. In our opinion, such 2003 and 2002 information included in the financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein. The financial statement schedule of Green Mountain Power Corporation and subsidiaries as of December 31, 2001 was audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on that schedule in their report dated March 12, 2002. /s/DELOITTE & TOUCHE LLP Boston, MA February 25, 2004 REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS We have audited, in accordance with auditing standards generally accepted in the United States, the consolidated financial statements of Green Mountain Power Corporation included in this Form 10-K and have issued our report thereon dated March 12, 2002. Our report included an explanatory paragraph indicating that effective January 1, 2001, Green Mountain Power Corporation adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. Our audit was made for the purpose of forming an opinion on the basic financial statements taken as a whole. The schedule listed in the accompanying index to consolidated financial statements and schedule is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic consolidated financial statements. This schedule has been subjected to the auditing procedures applied in the audit of the basic consolidated financial statements, and in our opinion, fairly states, in all material respects, the financial data required to be set forth therein in relation to the basic consolidated financial statements taken as a whole. /s/ Arthur Andersen LLP Boston, Massachusetts March 12, 2002 The above report of Arthur Andersen LLP is a copy of the previously issued report, and the report has not been reissued by Arthur Andersen LLP. ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE The July 17, 2002 decision to engage Deloitte & Touche LLP was made after careful consideration by the Green Mountain Power Corporation Board of Directors and senior management. The decision was not the result of any disagreement between Green Mountain Power and Arthur Andersen on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, for any periods audited and reported on by Arthur Andersen. Arthur Anderson's audit reports for the year ended December 31, 2001 did not contain any qualification, modification, or disclaimers. ITEM 9A. CONTROLS AND PROCEDURES Pursuant to Rule 13a-15(b) under the Securities and Exchange Act of 1934, we carried out an evaluation, with the participation of our management, including Christopher L. Dutton, President and Chief Executive Officer and Robert J. Griffin, Chief Financial Officer, Vice President and Treasurer (principal 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 of the end of the period covered by this report. Based upon that evaluation, our President and Chief Executive Officer, and our Chief Financial Officer, Vice President and Treasurer (principal financial officer) concluded that our disclosure controls and procedures are effective in timely alerting them to material information relating to us (including our consolidated subsidiaries) required to be included in our periodic SEC filings. There has been no change in our internal control over financial reporting during the quarter ended December 31, 2003 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. PART III ITEMS 10, 11, 12 AND 13 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, as well as that called for by Items 11, 12, and 13, "Executive Compensation," "Security Ownership of Certain Beneficial Owners and Management" and "Certain Relationships and Related Transactions," will be set forth under the captions "Election of Directors," Board Compensation, Meetings, Committees and Other Relationships, "Section 16(a) Beneficial Ownership Reporting Compliance," "Executive Compensation and Other Information", "Compensation Committee Report on Executive Compensation", "Pension Plan Information and Other Benefits" and "Securities Ownership of Certain Beneficial Owners and Management" in the Company's definitive proxy statement relating to its annual meeting of stockholders to be held on May 20, 2004. 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 March 2004. ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES Fees Paid to Deloitte & Touche During the fiscal year ended December 31, 2003, Deloitte & Touche was employed principally to perform the annual audit and to render other services. Fees paid to Deloitte & Touche for services rendered in fiscal years 2002 and 2003 are listed in the following table. Years ended December 31, 2003 2002 -------- -------- Audit Fees . . . . $160,471 $162,484 Audit-Related Fees . . . . . . 7,000 - Tax Services Fees. . . . . . . 36,577 54,147 All other fees . . . . - - Total Deloitte and Touche fees $204,048 $216,631 ======== ======== Fees paid during 2002 include audit fees of $9,000 and tax fees of $6,050 paid to Arthur Andersen for services rendered during 2002. Audit Fees include fees for services performed to comply with Generally Accepted Auditing Standards (GAAS), including the recurring audit of the Company's financial statements. This category also includes fees for audits provided in connection with statutory filings or services that generally only the principal auditor reasonably can provide to a client, such as procedures related to audit of income tax provisions and related reserves, consents and assistance with and review of documents filed with the Securities and Exchange Commission. Audit-Related Fees include fees associated with assurance and related services that are reasonably related to the performance of the audit or review of the Company's financial statements. This category includes fees related to assistance with implementation of the new Securities and Exchange Commission and Sarbanes-Oxley Act of 2002 requirements. Audit-related fees also include audits of employee benefit plans. Tax Fees primarily include fees associated with tax audits, tax compliance, tax consulting, as well as tax planning. ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K Item 15(a)1. Financial Statements and Schedules. The financial statements and financial statement schedules of the Company are listed on the Index to financial statements set forth in Item 8 hereof. Item 15(b) The following filings on Form 8-K were filed by the Company on the topic and date indicated: On December 23, 2003, a Form 8-K filing announced the VPSB approval of a Memorandum of Understanding with the DPS regarding rate stability, rate increases, and the amortization of the Pine Street Barge Canal costs. On December 10, 2003, a Form 8-K filing announced that the Board of Directors had approved changes to the Company's Bylaws. On December 3, 2003, a Form 8-K filing announced a presentation by Christopher L. Dutton, the President and CEO, and Robert J. Griffin, CFO, at an electric industry conference entitled "Investing in the Electric Utilities Industry". The accompanying notes are an integral part of these consolidated financial statements. ITEM 15(A)3 AND ITEM 15C. EXHIBITS SEC DOCKET , INCORPORATED BY EXHIBIT REFERENCE OR NUMBER DESCRIPTION EXHIBIT PAGE FILED HEREWITH ---------- -- ---------- ---------------------- 3-A RESTATED ARTICLES OF ASSOCIATION, AS CERTIFIED . . . . 3-A FORM 10-K 1993 JUNE 6, 1991. (1-8291) 3-A-1 AMENDMENT TO 3-A ABOVE, DATED AS OF MAY 20, 1993.. . . . . . . 3-A-1 FORM 10-K 1993 (1-8291) 3-A-2 AMENDMENT TO 3-A ABOVE, DATED AS OF OCTOBER 11, 1996.. . . . . 3-A-2 FORM 10-Q SEPT. 1996 (1-8291) 3-B BY-LAWS OF THE COMPANY, AS AMENDED . . . . 3-B FORM 10-K 1996 FEBRUARY 10, 1997. (1-8291) 3-C BY-LAWS OF THE COMPANY, AS AMENDED . . . . 3-C FORM 8-K DEC. 12, 2004 DECEMBER 8, 2004 (1-8291) 4-B-1 INDENTURE OF FIRST MORTGAGE AND DEED OF TRUST. . . . . 4-B 2-27300 DATED AS OF FEBRUARY 1, 1955. 4-B-2 FIRST SUPPLEMENTAL INDENTURE DATED AS OF . . . . 4-B-2 2-75293 APRIL 1, 1961. 4-B-3 SECOND SUPPLEMENTAL INDENTURE DATED AS OF. . . . . 4-B-3 2-75293 JANUARY 1, 1966. 4-B-4 THIRD SUPPLEMENTAL INDENTURE DATED AS OF . . . . 4-B-4 2-75293 JULY 1, 1968. 4-B-5 FOURTH SUPPLEMENTAL INDENTURE DATED AS OF. . . . . 4-B-5 2-75293 OCTOBER 1, 1969. 4-B-6 FIFTH SUPPLEMENTAL INDENTURE DATED AS OF . . . . 4-B-6 2-75293 DECEMBER 1, 1973. 4-B-7 SEVENTH SUPPLEMENTAL INDENTURE DATED AS. . . . . 4-A-7 2-99643 AUGUST 1, 1976. 4-B-8 EIGHTH SUPPLEMENTAL INDENTURE DATED AS OF. . . . . 4-A-8 2-99643 DECEMBER 1, 1979. 4-B-9 NINTH SUPPLEMENTAL INDENTURE DATED AS OF . . . . 4-B-9 2-99643 JULY 15, 1985. 4-B-10 TENTH SUPPLEMENTAL INDENTURE DATED AS OF . . . . 4-B-10 FORM 10-K 1989 JUNE 15, 1989. (1-8291) 4-B-11 ELEVENTH SUPPLEMENTAL INDENTURE DATED AS OF. . . . . 4-B-11 FORM 10-Q SEPT. SEPTEMBER 1, 1990. 1990 (1-8291) 4-B-12 TWELFTH SUPPLEMENTAL INDENTURE DATED AS OF . . . . 4-B-12 FORM 10-K 1991 MARCH 1, 1992. (1-8291) 4-B-13 THIRTEENTH SUPPLEMENTAL INDENTURE DATED AS OF. . . . . 4-B-13 FORM 10-K 1991 MARCH 1, 1992. (1-8291) 4-B-14 FOURTEENTH SUPPLEMENTAL INDENTURE DATED AS OF. . . . . 4-B-14 FORM 10-K 1993 NOVEMBER 1, 1993. (1-8291) 4-B-15 FIFTEENTH SUPPLEMENTAL INDENTURE DATED AS OF . . . . 4-B-15 FORM 10-K 1993 NOVEMBER 1, 1993. (1-8291) 4-B-16 SIXTEENTH SUPPLEMENTAL INDENTURE DATED AS OF . . . . 4-B-16 FORM 10-K 1995 DECEMBER 1, 1995. (1-8291) 4-B-17 REVISED FORM OF INDENTURE AS FILED AS AN EXHIBIT . . . . 4-B-17 FORM 10-Q SEPT. TO REGISTRATION STATEMENT NO. 33-59383. 1995 (1-8291) 4-B-18 CREDIT AGREEMENT BY AND AMONG GREEN MOUNTAIN POWER . . . . . . 4-B-18 FORM 10-K 1997 THE BANK OF NOVA SCOTIA, STATE STREET BANK AND (1-8291) TRUST COMPANY, FLEET NATIONAL BANK, AND FLEET NATIONAL BANK, AS AGENT 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 . . . . 4-B-19 FORM 10-K 2002 DECEMBER 1, 2002 (1-8291) 10-A FORM OF INSURANCE POLICY ISSUED BY PACIFIC . . . . 10-A 33-8146 INSURANCE COMPANY, WITH RESPECT TO INDEMNIFICATION OF DIRECTORS AND OFFICERS. 10-B-1 FIRM POWER CONTRACT DATED SEPTEMBER 16, 1958,. . . . . 13-B 2-27300 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. 10-B-2 POWER CONTRACT, DATED FEBRUARY 1, 1968, BETWEEN THE COMPANY. . 13-D 2-34346 AND VERMONT YANKEE NUCLEAR POWER CORPORATION. 10-B-3 AMENDMENT, DATED JUNE 1, 1972, TO

POWER CONTRACT . . . . 13-F-1 2-49697 BETWEEN THE COMPANY AND VERMONT YANKEE NUCLEAR POWER CORPORATION. 10-B-3(A) AMENDMENT, DATED APRIL 15, 1983, TO POWER. . . . . 10-B-3(A) 33-8164 CONTRACT BETWEEN THE COMPANY AND VERMONT YANKEE NUCLEAR POWER CORPORATION. 10-B-3(B) ADDITIONAL POWER CONTRACT, DATED . . . . 10-B-3(B) 33-8164 FEBRUARY 1, 1984,BETWEEN THE COMPANY AND VERMONT YANKEE NUCLEAR POWER CORPORATION. 10-B-4 CAPITAL FUNDS AGREEMENT, DATED FEBRUARY 1, ... 13-E 2-34346 1968, BETWEEN THE COMPANY AND VERMONT YANKEE NUCLEAR POWER CORPORATION. 10-B-5 AMENDMENT, DATED MARCH 12, 1968, TO CAPITAL. . . . . 13-F 2-34346 FUNDS AGREEMENT BETWEEN THE COMPANY AND VERMONT YANKEE NUCLEAR POWER CORPORATION. 10-B-6 GUARANTEE AGREEMENT, DATED NOVEMBER 5, 1981, OF THE. . . . . . 10-B-6 2-75293 COMPANY FOR ITS PROPORTIONATE SHARE OF THE OBLIGATIONS OF VERMONT YANKEE NUCLEAR POWER CORPORATION UNDER A $40 MILLION LOAN ARRANGEMENT. 10-B-7 THREE-PARTY POWER AGREEMENT AMONG THE COMPANY, ... 13-I 2-49697 VELCO AND CENTRAL VERMONT PUBLIC SERVICE CORPORATION DATED NOVEMBER 21, 1969. 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 . . . . 13-J 2-49697 COMPANY, VELCO AND CENTRAL VERMONT PUBLIC SERVICE CORPORATION, DATED NOVEMBER 21, 1969. 10-B-10 AMENDMENT TO EXHIBIT 10-B-9, DATED JUNE 1, 1981. . . . . 10-B-10 2-75293 10-B-14 AGREEMENT WITH CENTRAL MAINE POWER COMPANY ET. . . . . 5.16 2-52900 AL, TO ENTER INTO JOINT OWNERSHIP OF WYMAN PLANT, DATED NOVEMBER 1, 1974. 10-B-15 NEW ENGLAND POWER POOL AGREEMENT AS AMENDED TO . . . . 4.8 2-55385 NOVEMBER 1, 1975. 10-B-16 BULK POWER TRANSMISSION CONTRACT BETWEEN THE . . . . 13-V 2-49697 COMPANY AND VELCO DATED JUNE 1, 1968. 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. . . . . 10-B-20 33-8164 AMENDED OCTOBER 1, 1977, AND RELATED TRANSMISSION AGREEMENT, WITH THE MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY. 10-B-21 AGREEMENT DATED OCTOBER 1, 1977, FOR JOINT OWNERSHIP,. . . . . 10-B-21 33-8164 CONSTRUCTION AND OPERATION OF THE MMWEC PHASE I INTERMEDIATE UNITS, DATED OCTOBER 1, 1977 10-B-28 CONTRACT DATED FEBRUARY 1, 1980, PROVIDING FOR . . . . 10-B-28 33-8164 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-30 BULK POWER PURCHASE CONTRACT DATED APRIL 7,. . . . . 10-B-32 2-75293 1976, BETWEEN VELCO AND THE COMPANY. 10-B-33 AGREEMENT AMENDING NEW ENGLAND POWER POOL AGREEMENT. . . . . . 10-B-33 33-8164 DATED AS OF DECEMBER 1, 1981, PROVIDING FOR USE OF TRANSMISSION INTER-CONNECTION BETWEEN NEW ENGLAND AND HYDRO-QUEBEC. 10-B-34 PHASE I TRANSMISSION LINE SUPPORT AGREEMENT. . . . . 10-B-34 33-8164 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-35 PHASE I TERMINAL FACILITY SUPPORT AGREEMENT. . . . . 10-B-35 33-8164 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-36 AGREEMENT WITH RESPECT TO USE OF QUEBEC. . . . . 10-B-36 33-8164 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-39 VERMONT PARTICIPATION AGREEMENT FOR QUEBEC . . . . 10-B-39 33-8164 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 INTER- CONNECTION BETWEEN NEW ENGLAND AND HYDRO-QUEBEC. 10-B-40 VERMONT ELECTRIC TRANSMISSION COMPANY, INC.. . . . . 10-B-40 33-8164 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 INTER-CONNECTION BETWEEN NEW ENGLAND AND HYDRO-QUEBEC. 10-B-41 VETCO CAPITAL FUNDS SUPPORT AGREEMENT DATED AS . . . . 10-B-41 33-8164 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-42 ENERGY BANKING AGREEMENT DATED MARCH 21, 1983, ... 10-B-42 33-8164 AMONG HYDRO-QUEBEC, VELCO, NEET AND PARTI- CIPATING 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-43 INTERCONNECTION AGREEMENT DATED MARCH 21, 1983,. . . . . 10-B-43 33-8164 BETWEEN HYDRO-QUBEC 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-44 ENERGY CONTRACT DATED MARCH 21, 1983, BETWEEN. . . . . 10-B-44 33-8164 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-50 AGREEMENT FOR JOINT OWNERSHIP, CONSTRUCTION AND. . . . . 10-B-50 33-8164 OPERATION OF THE HIGHGATE TRANSMISSION INTERCONNECTION, DATED AUGUST 1, 1984, BETWEEN CERTAIN ELECTRIC DISTRIBUTION COMPANIES, INCLUDING THE COMPANY. 10-B-51 HIGHGATE OPERATING AND MANAGEMENT AGREEMENT, ... 10-B-51 33-8164 DATED AS OF AUGUST 1, 1984, AMONG VELCO AND VERMONT ELECTRIC-UTILITY COMPANIES, INCLUDING THE COMPANY. 10-B-52 ALLOCATION CONTRACT FOR HYDRO-QUEBEC FIRM POWER. . . . . 10-B-52 33-8164 DATED JULY 25, 1984, BETWEEN THE STATE OF VERMONT AND VARIOUS VERMONT ELECTRIC UTILITIES, INCLUDING THE COMPANY. 10-B-53 HIGHGATE TRANSMISSION AGREEMENT DATED AS OF. . . . . 10-B-53 33-8164 AUGUST 1, 1984, BETWEEN THE OWNERS OF THE PROJECT AND VARIOUS VERMONT ELECTRIC DISTRIBUTION COMPANIES. 10-B-61 AGREEMENTS ENTERED IN CONNECTION WITH PHASE II . . . . 10-B-61 33-8164 OF THE NEPOOL/HYDRO-QUEBEC + 450 KV HVDC TRANSMISSION INTERCONNECTION. 10-B-62 AGREEMENT BETWEEN UNITIL POWER CORP. AND THE . . . . 10-B-62 33-8164 COMPANY TO SELL 23 MW CAPACITY AND ENERGY FROM STONY BROOK INTERMEDIATE COMBINED CYCLE UNIT. 10-B-68 FIRM POWER AND ENERGY CONTRACT DATED DECEMBER 4, ... 10-B-68 FORM 10-K 1992 1987, BETWEEN HYDRO-QUEBEC AND PARTICIPATING (1-8291) VERMONT UTILITIES, INCLUDING THE COMPANY, FOR THE PURCHASE OF FIRM POWER FOR UP TO THIRTY YEARS. 10-B-69 FIRM POWER AGREEMENT DATED AS OF OCTOBER 26, 1987, ... 10-B-69 FORM 10-K 1992 BETWEEN ONTARIO HYDRO AND VERMONT DEPARTMENT OF (1-8291) PUBLIC SERVICE. 10-B-70 FIRM POWER AND ENERGY CONTRACT DATED AS OF . . . . 10-B-70 FORM 10-K 1992 FEBRUARY 23, 1987, BETWEEN THE VERMONT JOINT (1-8291) OWNERS OF THE HIGHGATE FACILITIES AND HYDRO- QUEBEC FOR UP TO 50 MW OF CAPACITY. 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. . . . . 10-B-71 FORM 10-K 1992 FEBRUARY 23, 1987, BETWEEN THE VERMONT JOINT (1-8291) OWNERS OF THE HIGHGATE FACILITIES AND HYDRO-QUEBEC. 10-B-72 PARTICIPATION AGREEMENT DATED AS OF APRIL 1, 1988, ... 10-B-72 FORM 10-Q BETWEEN HYDRO-QUEBEC AND PARTICIPATING VERMONT JUNE 1988 UTILITIES, INCLUDING THE COMPANY, IMPLEMENTING (1-8291) 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(A) RESTATEMENT OF THE PARTICIPATION AGREEMENT FILED . . . . 10-B-72(A) FORM 10-K 1988 AS EXHIBIT 10-B-72 ON FORM 10-Q FOR JUNE 1988. (1-8291) 10-B-77 FIRM POWER AND ENERGY CONTRACT DATED DECEMBER 29,. . . . . . . 10-B-77 FORM 10-K 1988 1988, BETWEEN HYDRO-QUEBEC AND PARTICIPATING (1-8291) VERMONT UTILITIES, INCLUDING THE COMPANY, FOR THE PURCHASE OF UP TO 54 MW OF FIRM POWER AND ENERGY. 10-B-78 TRANSMISSION AGREEMENT DATED DECEMBER 23, 1988,. . . . . 10-B-78 FORM 10-K 1988 BETWEEN THE COMPANY AND NIAGARA MOHAWK POWER (1-8291) CORPORATION (NIAGARA MOHAWK), FOR NIAGARA MOHAWK TO

PROVIDE ELECTRIC 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. . . . . 10-B-81 FORM 10-Q THE TOWN OF HARDWICK, HARDWICK ELECTRIC DEPARTMENT JUNE 1989 AND THE COMPANY FOR THE COMPANY TO PURCHASE (1-8291) 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-82 SALES AGREEMENT DATED JULY 14, 1989, BETWEEN . . . . 10-B-82 FORM 10-Q NORTHFIELD ELECTRIC DEPARTMENT AND THE COMPANY JUNE 1989 FOR THE COMPANY TO PURCHASE ALL OF THE OUTPUT (1-8291) 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-85 POWER PURCHASE AND SALE AGREEMENT BETWEEN. . . . . 10-B-85 FORM 10-K 1998 MORGAN STANLEY CAPITAL GROUP INC. AND THE (1-8291) COMPANY 10-B-86 REVOLVING CREDIT AGREEMENT WITH KEYBANK. . . . . 10-B-86 FORM 10-Q SEPT. 2000 (1-8291) 10-B-87 AMENDMENT TO FLEET REVOLVING CREDIT AGREEMENT. . . . . 10-B-87 FORM 10-Q SEPT. 2000 (1-8291) 10-B-88 ENERGY EAST POWER PURCHASE OPTION AGREEMENT. . . . . 10-B-88 FORM 10-Q SEPT. 2000 (1-8291) 10-B-89 SECOND AMENDED AND RESTATED CREDIT AGREEMENT BETWEEN . . . . . 10-B-89 FORM 10-K 2001 KEYBANK NATIONAL ASSOCIATION, FLEET NATIONAL BANK, AND THE COMPANY DATED JUNE 20, 2001 10-B-90 PURCHASE POWER AGREEMENT BETWEEN ENTERGY NUCLEAR VERMONT . . . 10-B-90 FORM 10-Q JUNE 2002 YANKEE LLC AND VERMONT YANKEE NUCLEAR POWER CORPORATION (1-8291) 10-B-91 FIRST AMENDMENT TO PURCHASE POWER AGREEMENT LISTED AS. . . . . 10-B-90 FORM 10-Q JUNE 2002 EXHIBIT NUMBER 10-B-90, BETWEEN ENTERGY NUCLEAR VERMONT YANKEE (1-8291) LLC AND VERMONT YANKEE NUCLEAR POWER CORPORATION 10-B-92 AMENDMENT TO POWER PURCHASE AND SALE AGREEMENT . . . . 10-B-92 FORM 10-K 2002 BETWEEN MORGAN STANLEY CAPITAL GROUP, INC. AND THE (1-8291) COMPANY MANAGEMENT CONTRACTS OR COMPENSATORY PLANS OR ARRANGEMENTS REQUIRED TO BE FILED AS EXHIBITS TO THIS FORM 10-K PURSUANT TO ITEM 14(C)., ALL UNDER SEC DOCKET 1-8291 --- 10-D-1B. GREEN MOUNTAIN POWER CORPORATION SECOND AMENDED 10-D-1B FORM 10-K 1993 AND RESTATED DEFERRED COMPENSATION PLAN FOR DIRECTORS. 10-D-1C. GREEN MOUNTAIN POWER CORPORATION SECOND AMENDED 10-D-1C FORM 10-K 1993 AND RESTATED DEFERRED COMPENSATION PLAN FOR OFFICERS. 10-D-1D. AMENDMENT NO. 93-1 TO THE AMENDED AND RESTATED 10-D-1D FORM 10-K 1993 DEFERRED COMPENSATION PLAN FOR OFFICERS. 10-D-1E. AMENDMENT NO. 94-1 TO THE AMENDED AND RESTATED 10-D-1E FORM 10-Q DEFERRED COMPENSATION PLAN FOR OFFICERS. JUNE 1994 10-D-2 . GREEN MOUNTAIN POWER CORPORATION MEDICAL EXPENSE 10-D-2 FORM 10-K 1991 REIMBURSEMENT PLAN. 10-D-4 . GREEN MOUNTAIN POWER CORPORATION OFFICER 10-D-4 FORM 10-K 1991 INSURANCE PLAN. 10-D-4A. GREEN MOUNTAIN POWER CORPORATION OFFICERS' 10-D-4A FORM 10-K 1990 INSURANCE PLAN AS AMENDED. 10-D-8 . GREEN MOUNTAIN POWER CORPORATION OFFICERS' 10-D-8 FORM 10-K 1990 SUPPLEMENTAL RETIREMENT PLAN. 10-D-15B GREEN MOUNTAIN POWER CORPORATION COMPENSATION PROGRAM 10-D-15B FORM 10-K 1997 FOR OFFICERS AND KEY MANAGEMENT PERSONNEL AS AMENDED AUGUST 4, 1997 10-D-15C GREEN MOUNTAIN POWER 2000 STOCK INCENTIVE PLAN 10-D-15C FORM 10-K 2001 10-D-40. SEVERANCE AGREEMENT WITH C. L. DUTTON 10-D-40 FORM 10-K 2003 10-D-41. SEVERANCE AGREEMENT WITH D.J. RENDALL 10-D-41 FORM 10-K 2003 10-D-42. SEVERANCE AGREEMENT WITH R. J. GRIFFIN 10-D-42 FORM 10-K 2003 10-D-43. SEVERANCE AGREEMENT WITH W. S. OAKES 10-D-43 FORM 10-K 2003 10-D-44. SEVERANCE AGREEMENT WITH M. G. POWELL 10-D-44 FORM 10-K 2003 10-D-45. SEVERANCE AGREEMENT WITH S. C. TERRY 10-D-45 FORM 10-K 2003 10-D-46. DEFERRED STOCK UNIT AGREEMENT WITH D.J. RENDALL 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 2004 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 L. E. CHICKERING 10-D-56 FORM 10-K 2003 10-D-57. DEFERRED STOCK UNIT AGREEMENT WITH J. V. CLEARY 10-D-57 FORM 10-K 2003 10-D-58. DEFERRED STOCK UNIT AGREEMENT WITH D.R. COATES 10-D-58 FORM 10-K 2003 10-D-59. DEFERRED STOCK UNIT AGREEMENT WITH E. A. IRVING 10-D-59 FORM 10-K 2003 10-D-60. DIRECTOR DEFERRAL AGREEMENT WITH E. A. BANKOWSKI 10-D-60 FORM 10-K 2003 10-D-61. DIRECTOR DEFERRAL AGREEMENT WITH M. O. BURNS 10-D-61 FORM 10-K 2003 10-D-62. DIRECTOR DEFERRAL AGREEMENT WITH D. R. COATES 10-D-62 FORM 10-K 2003 10-D-63. DIRECTOR DEFERRAL AGREEMENT WITH E. A. IRVING 10-D-63 FORM 10-K 2003 *23-A-1. CONSENT OF ARTHUR ANDERSEN LLP 23-A-1 23-A-2 . CONSENT OF DELOITTE AND TOUCHE LLP 23-A-2 24 . . . LIMITED POWER OF ATTORNEY 24 EXHIBIT 24 POWER OF ATTORNEY ----------------- We, the undersigned directors of Green Mountain Power Corporation, hereby severally constitute Christopher L. Dutton, Mary G. Powell, and Robert J. Griffin, and each of them singly, our true and lawful attorney with full power of substitution, to sign for us and in our names in the capacities indicated below, the Annual Report on Form 10-K of Green Mountain Power Corporation for the fiscal year ended December 31, 2003, and generally to do all such things in our name and behalf in our capacities as directors to enable Green Mountain Power Corporation to comply with the provisions of the Securities Exchange Act of 1934, as amended, all requirements of the Securities and Exchange Commission, and all requirements of any other applicable law or regulation, hereby ratifying and confirming our signatures as they may be signed by our said attorney, to said Annual Report. SIGNATURE TITLE DATE --------- ----- ---- /s/Christopher L. Dutton President and Director February 25, 2004 ------------------------- Christopher L. Dutton (Principal Executive Officer) /s/Nordahl L. Brue March 4, 2004 -------------------- Nordahl L. Brue Chairman of the Board /s/Elizabeth A. Bankowski March 1, 2004 -------------------------- Elizabeth A. Bankowski Director /s/William H. Bruett March 3, 2004 ---------------------- William H. Bruett Director /s/Merrill O. Burns March 1, 2004 --------------------- Merrill O. Burns Director /s/Lorraine E. Chickering March 2, 2004 --------------------------- Lorraine E. Chickering Director /s/John V. Cleary March 4, 2004 ------------------- John V. Cleary Director /s/David R. Coates March 4, 2004 -------------------- David R. Coates Director /s/Euclid A. Irving March 1, 2004 --------------------- Euclid A. Irving Director 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. GREEN MOUNTAIN POWER CORPORATION Date: February 25, 2004 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_ President, Chief Executive February 25, 2004 ------------------------------ Christopher L. Dutton Officer, and Director /s/ Mary G. Powell_______ Chief Operating Officer, March 10, 2004 ---------------------------- Mary G. Powell Senior Vice President /s/ Robert J. Griffin Chief Financial Officer, Vice February 25, 2004 ------------------------ Robert J. Griffin President and Treasurer *Nordahl L. Brue) Chairman of the Board *Elizabeth Bankowski *William H. Bruett) *Merrill O. Burns) *David R. Coates) *Lorraine E. Chickering) *John V. Cleary) Directors *Euclid A. Irving) *By: _/s/ Christopher L. Dutton February 25, 2004 --------------------------- Christopher L. Dutton (Attorney - in - Fact)