THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Green Mountain Power Corp	End of 2016/Q2

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Green Mountain Power Corp	02 Year/Period of Report End of 2016/Q2
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 163 Acorn Lane Colchester, VT 05446	
05 Name of Contact Person Dawn D. Bugbee	06 Title of Contact Person Chief Financial Officer
07 Address of Contact Person *(Street, City, State, Zip Code)* 163 Acorn Lane Colchester, VT 05446	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(802) 655-8768	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016

QUARTERLY CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Dawn D. Bugbee		
02 Title Chief Financial Officer	Dawn D. Bugbee	08/26/2016

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. No changes to or purchases of franchise rights occurred.
2. There were no acquisitions of ownership in other companies by reorganization, merger, or consolidation with other companies.
3. No operating units were purchased or sold.
4. No important leaseholds were entered into or surrendered.
5. No important extensions or reductions of the transmission or distribution system.
6. See page 123 - Notes to Financial Statements for changes in short-term and long-term debt.
7. There were no changes in articles of incorporation or amendments to charter.
8. No significant changes to the wage scale occurred.
9. See page 123 - Notes to Financial Statements for discussion of legal proceedings.
10. None
11. Reserved
12. On May 4, 2016, GMP executed an Equity Capital Contribution Agreement with a tax equity partner to invest $60.1M in GMP VT Solar LLC to construct, operate and maintain 5 solar generating facilities located throughout Vermont. GMP will invest $39.6M and the tax equity partner will invest $20.5M. GMP's 2017 base rate filing will include its investment in rate base and investment earnings and project developer fees will be offset against cost of service. As of June 30, 2016, GMP has invested $15M in GMP VT Solar LLC.

    The operating agreement for GMP Solar-VT LLC was amended to reflect a 40% ownership interest in GMP Solar-VT LLC by a third party tax equity investor. The operating agreements for GMP Solar-Panton LLC, GMP Solar-Hartford LLC, GMP Solar-Williston LLC, GMP Solar-Williamstown LLC, and GMP Solar –Richmond LLC were all amended to reflect GMP Solar –VT LLC as the sole member, and GMP as the manager. These amendments all occurred coincident with the GMP's equity capital contribution closing with the tax equity partner on May 4, 2016.

    Fiscal Year (FY) 2016 (October 1, 2015 – September 30, 2016) is the first year synergy savings are shared 50/50 with customers. $13.3M was included in the FY 2016 base rate filing as an estimate of the customers' share of FY 2016 synergy savings. GMP will record an entry in FY 2016 for 50% of the difference between actual FY 2016 synergy savings and $26.6M. Through June 30, 2016, GMP has recorded a regulatory liability of $1.3M for the customers' share of synergy savings in excess of $26.6M which GMP is expected to realize in FY 2016.

    GMP, through wholly-owned subsidiaries, owns a 26% limited partnership interest in a California partnership which operates a wind farm in California. The partnership has recorded significant tax and book losses over the years. GMP has been able to utilize the tax losses to reduce income taxes paid by GMP and GMP's book investment balance in the partnership has been written down to $0. The partnership ceased operations in November 2015. In June 2016, GMP sold its partnership interest for $10 to the general partner. A condition precedent to the sale was the cancellation of a partnership note payable. The note cancelation and sale resulted in GMP incurring a current federal income tax payable of approximately $5.0M. GMP utilized a portion of its net operating loss to offset this federal income tax payable and no cash payment was required. GMP will be required to make a $0.8M state income tax payment to California. GMP will record a book income tax expense of $0.5M related to the sale.

On July 15, 2016 GMP reached an agreement with a third party to acquire 14 small hydroelectric generating plants in New England and purchase the output of two other hydro plants under 25 year purchase power agreements. The acquisition is priced at $20.3 million and is expected to close in Fiscal Year 2017 subject to VT regulatory approval. In a typical year the acquisition plants will add approximately 51,000 MWH of renewable energy to the GMP portfolio while the purchase power agreements will add just over 100,000 MWH of fixed price renewable energy each year.

On August 1, 2016, GMP filed its proposed 2017 base rate adjustment with the Public Service Board (PSB). The filing, covering the period October 1, 2016 to September 30, 2017, included a 9.02% rate of return and a .03% base rate decrease. The filing also included a provision whereby $16.335M in synergy savings (resulting from the acquisition of Central Vermont Public Service Corporation by GMP and equivalent to 50% of projected total synergy savings for the time period October 1, 2016 to September 30, 2017) would be returned to GMP's customers.

Also, see page 123 - Notes to Financial Statements

13. None

14. Not Applicable

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	1,659,849,652	1,624,536,211
3	Construction Work in Progress (107)	200-201	48,546,219	52,672,225
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,708,395,871	1,677,208,436
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	607,613,726	594,685,586
6	Net Utility Plant (Enter Total of line 4 less 5)		1,100,782,145	1,082,522,850
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		1,616,100	242,274
9	Nuclear Fuel Assemblies in Reactor (120.3)		3,997,916	3,997,916
10	Spent Nuclear Fuel (120.4)		15,074,702	15,074,702
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	18,140,165	17,729,029
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		2,548,553	1,585,863
14	Net Utility Plant (Enter Total of lines 6 and 13)		1,103,330,698	1,084,108,713
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		15,354,543	14,598,118
19	(Less) Accum. Prov. for Depr. and Amort. (122)		8,902,367	8,743,383
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	461,624,897	441,086,845
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		20,378,133	20,194,958
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		9,558,121	9,412,398
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		498,013,327	476,548,936
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		2,634,663	3,087,653
36	Special Deposits (132-134)		357,008	2,401,058
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		44,315,967	45,497,051
41	Other Accounts Receivable (143)		3,157,724	3,080,695
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		3,166,458	2,403,025
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		163,839	322,888
45	Fuel Stock (151)	227	7,128,415	7,837,177
46	Fuel Stock Expenses Undistributed (152)	227	53,924	81,602
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	15,206,178	12,743,452
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	910,836	844,400
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		1,270,847	7,818,603
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		1,464,000	2,094,729
61	Accrued Utility Revenues (173)		23,271,837	25,826,620
62	Miscellaneous Current and Accrued Assets (174)		4,752,148	5,832,674
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		491,778	12,235,781
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		102,012,706	127,301,358
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		5,114,595	5,294,372
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	1,501,676	1,806,885
73	Prelim. Survey and Investigation Charges (Electric) (183)		4,012,585	3,364,246
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		-38,787	-23,945
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	123,501,469	127,559,769
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		0	0
82	Accumulated Deferred Income Taxes (190)	234	119,200,654	128,713,013
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		253,292,192	266,714,340
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,956,648,923	1,954,673,347

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	end of 2016/Q2

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	333	333
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	510,097,237	510,097,237
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	67,831,225	63,405,400
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	95,348,386	89,668,495
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	0
16	Total Proprietary Capital (lines 2 through 15)		673,277,181	663,171,465
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	635,665,046	636,905,046
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	0
24	Total Long-Term Debt (lines 18 through 23)		635,665,046	636,905,046
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		3,860,421	3,241,792
29	Accumulated Provision for Pensions and Benefits (228.3)		11,257,551	11,922,180
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		8,113,954	7,918,549
35	Total Other Noncurrent Liabilities (lines 26 through 34)		23,231,926	23,082,521
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		48,927,391	45,067,297
38	Accounts Payable (232)		42,796,533	45,520,145
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		2,322,791	8,404,194
41	Customer Deposits (235)		1,033,380	1,525,609
42	Taxes Accrued (236)	262-263	2,191,252	4,133,434
43	Interest Accrued (237)		3,434,997	3,478,367
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	end of 2016/Q2

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,144,715	1,170,338
48	Miscellaneous Current and Accrued Liabilities (242)		12,256,084	9,649,191
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		932,645	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		115,039,788	118,948,575
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		337,645	370,973
57	Accumulated Deferred Investment Tax Credits (255)	266-267	3,464,765	3,564,576
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	69,040,395	81,530,965
60	Other Regulatory Liabilities (254)	278	635,078	624,017
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		277,941,400	265,915,263
64	Accum. Deferred Income Taxes-Other (283)		158,015,699	160,559,946
65	Total Deferred Credits (lines 56 through 64)		509,434,982	512,565,740
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,956,648,923	1,954,673,347

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Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	322,570,117	331,631,981	154,471,230	154,627,729
3	Operating Expenses					
4	Operation Expenses (401)	320-323	223,410,698	240,586,561	105,524,794	113,554,954
5	Maintenance Expenses (402)	320-323	21,518,901	21,695,830	10,271,862	10,360,376
6	Depreciation Expense (403)	336-337	19,291,741	17,970,981	9,760,731	9,142,625
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	69,888	30,377	34,944	34,944
8	Amort. & Depl. of Utility Plant (404-405)	336-337	6,711,022	5,920,077	3,358,014	3,021,757
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		5,876,669	1,288,001	2,300,641	633,824
13	(Less) Regulatory Credits (407.4)		2,548,602	1,125,769	1,249,242	562,885
14	Taxes Other Than Income Taxes (408.1)	262-263	17,580,393	16,473,748	8,784,734	8,111,937
15	Income Taxes - Federal (409.1)	262-263	95,020	49,953	63,562	77,191
16	- Other (409.1)	262-263				
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	13,825,661	14,217,796	7,282,281	5,581,688
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277				
19	Investment Tax Credit Adj. - Net (411.4)	266	-99,811	-139,927	-49,905	-69,963
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		119,131	114,384	59,565	57,192
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		305,850,711	317,082,012	146,141,981	149,943,640
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		16,719,406	14,549,969	8,329,249	4,684,089

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
322,570,117	331,631,981					2
						3
223,410,698	240,586,561					4
21,518,901	21,695,830					5
19,291,741	17,970,981					6
69,888	30,377					7
6,711,022	5,920,077					8
						9
						10
						11
5,876,669	1,288,001					12
2,548,602	1,125,769					13
17,580,393	16,473,748					14
95,020	49,953					15
						16
13,825,661	14,217,796					17
						18
-99,811	-139,927					19
						20
						21
						22
						23
119,131	114,384					24
305,850,711	317,082,012					25
16,719,406	14,549,969					26

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 06/30/2016	Year/Period of Report End of 2016/Q2

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		16,719,406	14,549,969	8,329,249	4,684,089
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		519,968	476,130	367,801	264,708
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		383,655	383,980	277,772	204,411
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)		551,921	789,526	294,586	687,678
36	Equity in Earnings of Subsidiary Companies (418.1)	119	30,441,256	31,095,588	14,949,413	15,341,754
37	Interest and Dividend Income (419)		13,190	129,215	2,054	40,505
38	Allowance for Other Funds Used During Construction (419.1)		405,226	539,969	212,285	177,698
39	Miscellaneous Nonoperating Income (421)		864	1,268	71	773
40	Gain on Disposition of Property (421.1)		51,651	138,500		134,850
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		31,600,421	32,786,216	15,548,438	16,443,555
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		62,620			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		71,023	146,622	44,723	82,687
46	Life Insurance (426.2)		151,684	-232,634	-16,351	2,418
47	Penalties (426.3)			85,719		85,719
48	Exp. for Certain Civic, Political & Related Activities (426.4)		117,325	85,843	35,104	42,302
49	Other Deductions (426.5)		2,221,060	1,872,426	1,029,438	932,919
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		2,623,712	1,957,976	1,092,914	1,146,045
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	21,000	19,998	10,500	9,999
53	Income Taxes-Federal (409.2)	262-263				
54	Income Taxes-Other (409.2)	262-263				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277				
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		21,000	19,998	10,500	9,999
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		28,955,709	30,808,242	14,445,024	15,287,511
61	Interest Charges					
62	Interest on Long-Term Debt (427)		17,239,223	16,472,721	8,613,603	8,230,075
63	Amort. of Debt Disc. and Expense (428)		228,506	224,811	117,243	110,941
64	Amortization of Loss on Reaquired Debt (428.1)					
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		341,599	658,955	174,696	317,342
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		229,606	305,541	120,289	100,545
70	Net Interest Charges (Total of lines 62 thru 69)		17,579,722	17,050,946	8,785,253	8,557,813
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		28,095,393	28,307,265	13,989,020	11,413,787
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		28,095,393	28,307,265	13,989,020	11,413,787

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		62,617,982	62,617,982
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		28,095,393	14,106,373
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-17,989,677	(8,994,837)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-17,989,677	(8,994,837)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		-5,679,891	(3,091,529)
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		67,043,807	64,637,989
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
39				
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		787,418	787,418
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		787,418	787,418
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		67,831,225	65,425,407
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	28,095,393	14,106,373
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	24,486,960	12,126,116
5	Amortization of	2,320,749	1,202,517
6		4,328,587	3,492,946
7			
8	Deferred Income Taxes (Net)	13,468,720	6,543,380
9	Investment Tax Credit Adjustment (Net)	-99,811	-49,906
10	Net (Increase) Decrease in Receivables	1,744,874	-923,693
11	Net (Increase) Decrease in Inventory	-2,437,571	-1,972,856
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	964,087	4,797,131
14	Net (Increase) Decrease in Other Regulatory Assets		
15	Net Increase (Decrease) in Other Regulatory Liabilities		
16	(Less) Allowance for Other Funds Used During Construction	405,226	192,941
17	(Less) Undistributed Earnings from Subsidiary Companies	6,147,966	2,992,638
18	Other (provide details in footnote):		
19	Other Assets	7,459,127	3,422,171
20	Other Liabilities	-2,038,033	-1,199,326
21	(Gain)/Loss on Disposal of Assets	10,969	10,969
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	71,750,859	38,370,243
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-43,464,638	-19,973,736
27	Gross Additions to Nuclear Fuel	-1,174,305	-1,174,305
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-11,892	-11,892
30	(Less) Allowance for Other Funds Used During Construction	-405,226	-192,941
31	Other (provide details in footnote):		
32			
33	All Other	-1,118,936	-672,951
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-45,364,545	-21,639,943
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-13,478,962	
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-1,631,439	-959,733
45	Proceeds from Sales of Investment Securities (a)	1,575,307	1,018,719

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 06/30/2016	Year/Period of Report End of 2016/Q2

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-58,899,639	-21,580,957
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68	Borrowings on Revolving Line of Credit	209,434,590	116,407,413
69	Repayments on Revolving Line of Credit	-205,574,497	-123,053,512
70	Cash Provided by Outside Sources (Total 61 thru 69)	3,860,093	-6,646,099
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-1,240,000	-1,240,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Debt Issuance Cost	-48,728	-48,051
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-17,919,625	-8,959,811
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-15,348,260	-16,893,961
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-2,497,040	-104,675
87			
88	Cash and Cash Equivalents at Beginning of Period	5,488,711	5,488,711
89			
90	Cash and Cash Equivalents at End of period	2,991,671	5,384,036

Schedule Page: 120 Line No.: 90 Column: b

Reconciliation of Cash and Cash Equivalents:

Account 131 (Cash)	$2,634,663
Accounts 132 - 134 (Special Deposits)	$357,008
Total	$2,991,671

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

The notes below are excerpts from the Company's GAAP basis consolidated financial statements as of and for the years ended September 30, 2015 and 2014. The following disclosures contain information in accordance with GAAP reporting requirements. As such, due to differences between FERC and GAAP reporting requirements, certain disclosures may not agree to balances in the FERC financial statements. In particular, the activity related to Vermont Yankee Nuclear Power Corporation may be presented in the GAAP notes, but has been eliminated in accordance with FERC reporting instructions.

(1) Nature of Operations

Green Mountain Power Corporation (the Company or GMP), a wholly owned subsidiary of Northern New England Energy Corporation (NNEEC), operates as an electric utility that purchases, generates, transmits, distributes, and sells electricity, and utility construction services, in Vermont to approximately 260,000 customer accounts. GMP was acquired by NNEEC (itself a wholly owned subsidiary of Gaz Metro Limited Partnership of Canada), on April 12, 2007. On June 27, 2012, NNEEC acquired, Central Vermont Public Service Corporation (CVPS). CVPS was then merged with and into GMP effective October 1, 2012.

The Company's primary revenues are generated from sales of its regulated electric utility operation. The Company is regulated by the Vermont Public Service Board (VPSB) and uses the Uniform System of Accounts established by the Federal Energy Regulatory Commission (FERC).

The Company's wholly owned subsidiaries include:

- **Vermont Yankee Nuclear Power Corporation (VYNPC):** VYNPC was formed on August 4, 1966 to construct and operate a nuclear-powered electric generating plant (the Plant). The Plant was sold to Entergy Nuclear Vermont Yankee, LLC (Entergy) on July 31, 2002. As part of the sale, VYNPC was required to purchase from Entergy all of the facility product (energy, capacity and other facility product) available from the Plant at the time of the sale through March 21, 2012. The Plant was shut down on December 29, 2014. VYNPC recognizes revenue pursuant to the terms of its FERC filed rate schedule. The Sponsors, a group of seven New England utilities, are severally obligated to pay the Company their entitlement percentage of amounts equal to VYNPC's cost of service including total operating expenses and an allowed return on equity (7.5% since July 31, 2002). The Company's entitlement share is 55%. See note 16(h). VYNPC is subject to regulation by the FERC and the VPSB with respect to rates, accounting and other matters.

- **Central Vermont Public Service Corporation – East Barnet Hydroelectric, Inc. (East Barnet):** East Barnet was formed to finance and construct a hydroelectric facility in Vermont, which became operational on September 1, 1984. The Company has leased and operated this facility since the in-service date.

- **Catamount Resources Corporation (CRC):** CRC was formed to hold investments in unregulated business opportunities.

- **GMP Solar – Williston LLC, GMP Solar – Richmond LLC and GMP Solar – Hartford LLC:** were formed in February 2015 to construct renewable energy projects. Once construction is completed a third party tax equity partner will invest in this entity.

- **Northern Water Resources, Inc. (NWR):** NWR holds a limited partnership interest in a California wind farm. Though no book value remains for the wind farm assets, a deferred tax liability of $5,283 and $4,758, respectively, exists at September 30, 2015 and 2014.

(2) Summary of Significant Accounting Policies

(a) Principles of Consolidation and Presentation

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States (GAAP). All intercompany transactions with consolidated affiliates have been eliminated upon consolidation.

The Company accounts for its investments in Vermont Electric Power Company, Inc. (VELCO), Vermont Transco LLC (Transco), Green Lantern Capital Solar Fund II, LP (GLC), New England Hydro-Transmission Corporation, and New England Hydro-Transmission Electric Company, Connecticut Yankee Atomic Power Company (Connecticut Yankee), Maine Yankee Atomic Power Company (Maine Yankee) and Yankee Atomic Electric Company (Yankee Atomic) using the equity method of accounting. The Company's share of the net earnings or losses of these companies is included in equity in earnings of associated companies on the consolidated statements of income.

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 within utility plant in service. The Company's share of operating expenses for these facilities is included in the corresponding operating accounts in the consolidated statements of income.

The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting period. The Company believes it has taken reasonable positions where assumptions and estimates are used. In management's opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of unbilled revenue, pension and postretirement plan assumptions, contingency reserves, asset retirement obligations, regulatory assets and liabilities, the allowance for uncollectible accounts receivable, the valuation of utility plant, income tax uncertainties, deferred tax assets and derivative financial instruments. Actual results could differ from those estimates.

The Company considers events or transactions that occur after the balance sheet date, but before the consolidated financial statements are available to be issued, to provide additional evidence relative to certain estimates or to identify matters that require additional disclosure. These consolidated financial statements were available to be issued on November 19, 2015 and subsequent events have been evaluated through that date.

(b) Regulatory Accounting

The Company's utility operations, including accounting records, rates, operations, and certain other practices, are subject to the regulatory authority of the FERC and the VPSB.

The Company accounts for certain transactions in accordance with permitted regulatory treatment. As such, regulators may permit specific incurred costs, typically treated as expenses by unregulated entities, to be deferred and expensed in future periods when it is probable that such costs will be recovered in customer rates. Incurred costs are deferred as regulatory assets when the Company concludes that it is probable that future revenues 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. A regulatory liability is recorded when amounts that have been recorded by the Company are likely to be refunded to customers through the rate-setting process. Regulatory assets and liabilities also include changes in fair value relative to derivative financial instruments that cannot be considered as income or expense for rate-making purposes until the derivative financial instrument settles.

(c) ***Cash and Cash Equivalents***

The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents. Cash that is restricted for outstanding workers' compensation claims and for use under the terms of VPSB regulatory orders amounted to $391 and $488 at September 30, 2015 and 2014, respectively, and is included in cash and cash equivalents in the consolidated balance sheets. Included in cash are deposits, subject to the Company's exclusive control, provided as collateral under performance assurance requirements for certain power supply contracts amounting to $10 at September 30, 2015 and 2014.

Net book overdrafts, determined on a financial institution-specific basis, are reclassified from cash to other current liabilities in the consolidated balance sheets. Amounts reclassified as of September 30, 2015 and 2014 were $3,477 and $3,932, respectively. The Company has classified this activity on the consolidated statements of cash flows in net cash provided by operating activities.

(d) ***Revenue Recognition, Accounts Receivable, and Deferred Regulatory Revenue***

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. The unbilled revenues, which totaled $22,496 and $22,813 at September 30, 2015 and 2014, respectively, are included in trade accounts receivable in the consolidated balance sheets. Wholesale revenues represent sales of electricity to other utilities, typically for resale, and to ISO New England for amounts by which the Company's power supply resources exceed customer loads. Revenues in excess of allowed costs or earnings in excess of earnings allowed under applicable rate plans or regulatory orders are deferred, if and when applicable. See note 3. Sales taxes collected from commercial customers are accounted for as a liability until remitted to the government and are excluded from operating revenues in the consolidated statements of income.

The Company estimates the amount of accounts receivable that will not be collected and records an allowance for estimated uncollectible amounts based upon historical experience. Charge-offs against the allowance are considered after reviewing the facts of each individual account.

(e) ***Inventories***

The Company's inventory of generation fuel is accounted for on a first in, first out basis; Materials and supplies are recorded at cost and determined on a weighted average basis. Renewable energy certificates (RECs) are recorded at cost. The Company's inventories consist of the following:

		September 30 2015	September 30 2014
Fuel	$	7,138	6,568
Materials and Supplies		12,782	12,083
RECs		2,817	2,663
Total Inventory	$	22,737	21,314

The Company generates and purchases RECs in the normal course of business, and sells these RECs in order to reduce net power costs for GMP's retail customers through the power supply adjustor mechanism (see note 3). The Company accounts for purchased RECs using the inventory method. During the years ended September 30, 2015 and 2014, net REC revenue was $23,999 and $20,065, respectively. The Company has $2,817 and $2,663 of RECs inventory at September 30, 2015 and 2014, respectively, which represents the cost of RECs that were acquired in connection with certain power purchase agreements. The Company's self-generated RECs have an inventory carrying cost of zero.

(f) ***Utility Plant and Long-Lived Assets***

Utility plant is stated at cost. Major expenditures for plant additions are recorded at original cost and include all construction-related direct labor and materials, as well as indirect construction costs. The costs of renewals and improvements of significant property units are capitalized. The costs of maintenance, repairs, and replacements of minor property units are charged to maintenance expense. The costs of units of property removed from service, net of salvage value, are charged to accumulated depreciation.

Depreciation expense is recognized on a straight-line basis based on depreciation rates adopted as a result of depreciation studies approved by the VPSB. The VPSB approved new depreciation rates effective October 1, 2014. The net impact of the change in depreciation rates is an annual reduction in depreciation expense of approximately $5,000. 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.

(g) ***Long-Term Investments***

When an other-than-temporary impairment (OTTI) has occurred, the amount of the OTTI recognized in earnings depends on whether the Company intends to sell the security or more likely than not will be required to sell the security before recovery of its amortized cost basis less any current-period credit loss. If the Company intends to sell the security or more likely than not will be required to sell the security before recovery of its amortized cost basis less any current-period credit loss, the OTTI is recognized in earnings equal to the entire difference between the investment's amortized cost basis and its fair value at the balance sheet date.

If the Company does not intend to sell the security and it is not more likely than not that the Company will be required to sell the security before recovery of its amortized cost basis less any current-period credit loss, the OTTI is separated into the amount representing the credit loss and the amount related to all other factors. The amount of the total OTTI related to the credit loss is recognized in earnings. The credit loss component recognized in earnings is identified as the amount of principal cash flows not expected to be received over the remaining term of the security as projected using the Company's cash flow projections using its base assumptions.

A decline in the market value of any available-for-sale security below cost that is deemed to be other-than-temporary results in an impairment to reduce the carrying amount to fair value. To determine whether an impairment of a security is other-than-temporary, the Company considers whether evidence indicating the cost of the investment is recoverable outweighs evidence to the contrary. Evidence considered in this assessment includes the reasons for the impairment, the severity and duration of the impairment, changes in value subsequent to year-end, forecasted performance of the investee, and the general market condition in the geographic area or industry the investee operates in. The Company's assessment of the fair market value of its long-term investments is performed by fixed income investment professionals utilizing relevant performance indicators of the underlying assets in the security (including default rates, delinquency rates, and percentage of nonperforming assets, loan to collateral value ratios, third party guarantees, and current levels of subordination). For the years ended September 30, 2015 and 2014, there were no permanent impairments or credit losses associated with debt securities.

Millstone decommissioning trust fund: All dividend and interest income, realized and unrealized gains and losses are recorded to a regulatory liability since the fair value of the Millstone decommissioning trust fund exceeds the related asset retirement obligation. For debt securities, an OTTI exists if: 1) there is the intent to sell a debt security; 2) it is more likely than not that the security will be required to be sold prior to recovery; or 3) the entire unamortized cost of the security is not expected to be recovered. For the majority of the investments, GMP owns a share of the trust fund investments.

(h) Impairment of Long-Lived Assets

The Company performs an evaluation of long-lived assets, including utility plant, regulatory assets subject to amortization, and other long-lived assets, for potential impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the carrying value of the long-lived asset is not recoverable based on undiscounted cash flows expected to be generated by the asset, an impairment charge is recognized to the extent that the carrying value exceeds its fair value, with fair value being determined based upon discounted cash flow models. Regulatory assets are charged to expense in the period in which they are no longer probable of future recovery. As of September 30, 2015 and 2014, based upon management's analysis of the regulatory environment within which the Company currently operates, the Company does not believe that an impairment loss for long-lived assets should be recorded.

(i) 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 are considered probable and reasonably estimable. 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 will be recovered in future rates. Estimates are based on studies performed by third parties.

(j) Derivative Financial Instruments

There are three different ways to account for derivative instruments: (i) as an accrual agreement, if the criteria for the normal purchase normal sale exception are met and documented; (ii) as a cash flow or fair value hedge, if the specified criteria are met and documented, or (iii) as a mark to market agreement with changes in fair value recognized in current period earnings. All derivative instruments that do not qualify for the normal purchase normal sale exception are recorded at fair value in Derivative financial instrument assets and liabilities on the consolidated balance sheets.

Gains or losses resulting from changes in the fair values of derivatives are accounted for pursuant to a regulatory accounting order issued by the VPSB as discussed below. The Company uses derivative instruments primarily to hedge the cash flow effects of price fluctuations in its power supply costs. The Company is exposed to credit loss in the event of nonperformance by the other parties to the hedge agreements. The credit risk related to the hedge agreements is limited to the cost to the Company to replace the aforementioned hedge arrangements with like instruments. The Company monitors the credit standing of the counterparties and anticipates that the counterparties will be able to fully satisfy their obligations under the hedge agreements.

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 changes in the fair value of power supply arrangements that qualify as derivatives. Any changes in the fair value of the derivative financial instrument are recorded as a regulatory asset or liability, as appropriate. As these derivative contracts are settled, realized gains or losses are reclassified into earnings through electricity power supply costs.

(k) Purchased Power

The Company records the annual cost of power obtained under short-term and 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. The Company is not the sole taker of power from these sources except for the Moretown Landfill, North Hartland Hydro Unit 1, Brockway Mills Hydro, Lower Village Hydro, Lower Valley Hydro, Sweetwater Hydro, and Ampersand contracts.

(l) Taxes Other than Income

Taxes other than income consist primarily of various property taxes, Vermont gross receipts taxes and certain employer payroll tax expenses. The company recognizes the taxes in the period incurred.

(m) Income Taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. Investment tax credits are recorded as a liability and amortized as a tax expense benefit over the lives of the relevant assets.

The Company recognizes the effect of uncertain income tax positions only if those positions are more likely than not of being sustained. When recognized, income tax positions are measured and recorded at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs. The Company records interest expense related to unrecognized tax benefits in interest expense and penalties in other (expense) income, net in the consolidated statements of income.

The Company files a consolidated tax return with its Parent, NNEEC. NNEEC pays all federal and state income taxes on behalf of the Company. The Company has a tax-sharing agreement with NNEEC to pay an amount equal to the tax that would be paid if the Company filed tax returns on a separate return basis. There was no income taxes payable to or receivable from NNEEC under the tax-sharing agreement at

September 30, 2015 and 2014.

(n) Pension and Other Postretirement Benefit Plans

The Company has defined benefit pension plans covering certain of its employees. The benefits are based on years of service and the employee's compensation during the five years before retirement. GMP also sponsors defined benefit postretirement health care and life insurance plans for retired employees and their dependents. Effective January 1, 2008, for GMP and April 1, 2010, for former CVPS, newly hired employees are not eligible to participate in the Company's defined benefit pension plans, but instead qualify for an enhanced 401(k) benefit.

The Company records annual amounts relating to its pension and postretirement plans based on calculations that incorporate various actuarial and other assumptions, including discount rates, mortality, assumed rates of return, compensation increases, turnover rates, and healthcare cost trend rates. The Company reviews its assumptions on an annual basis and makes modifications to the assumptions based on current rates and trends. The effect of modifications to those assumptions is recorded as a regulatory asset or regulatory liability, as appropriate. The Company believes that the assumptions utilized in recording its obligations under its plans are reasonable based on its experience and market conditions.

The net periodic costs are recognized as employees render the services necessary to earn the postretirement benefits. Unamortized amounts that are expected to be recovered from or returned to ratepayers in future years are recorded as a regulatory asset or regulatory liability, respectively. See notes 3 and 13.

(o) Contingencies

Liabilities for loss contingencies arising from items such as claims, assessments, litigation, fines and penalties are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

(p) Fair Value

The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Company determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principal or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1 inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at measurement date.

The level in the fair value hierarchy within which a fair value measurement in its entirety falls is based on the lowest level input that is available for that particular financial instrument. The values of publicly traded fixed income and equity securities are based on quoted market prices and exchange rates. Non-marketable securities include alternative investments in hedge, private equity, and other similar funds, and are valued using current estimates of fair value in the absence of readily determinable market values. The fair values are determined by management based on information provided by the investment manager and are based on appraisals or other estimates that require varying degrees of judgment, which takes into consideration, among other things, the cost of the securities, prices of recent significant placements of securities of the same issuer, and subsequent developments concerning the companies to which the securities relate.

The estimated fair value of alternative investments represents the ownership interest in the net asset value (NAV) of the respective partnership. The Company utilizes the NAV reported by the fund managers, which is based on appraisals or other estimates that require varying degrees of judgment, as a practical expedient to estimate fair value of alternative investments that (a) do not have a readily determinable fair value and (b) either have the attributes of an investment company or prepare their financial statements consistent with the measurement principles of an investment company, unless it is probable that all or a portion of the investment will be sold for an amount different from NAV. With respect to those investments reported at NAV, as a practical expedient, classification in Level 2 or 3 is based on the Company's ability to redeem its interest at or near the date of the balance sheet. If the investment can be redeemed within ninety days of the date of the balance sheet, it is classified in Level 2; if not, it is classified as Level 3.

The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable, prepaid expenses and other current assets, income taxes receivable (payable), accounts payable, accrued liabilities, short-term debt, long-term debt, the spent fuel disposal fee and accrued interest obligation, the Millstone and Spent Fuel Decommissioning and Rabbi Trust funds, and pension assets.

(q) Government Grants

Government grants are recognized when there is reasonable assurance that the Company will comply with the conditions attached to the grant arrangement and the grant will be received. Government grants are recognized in the consolidated statements of income over the periods in which the related costs for which the government grant is intended to compensate are recognized. When government grants are related to reimbursements of operating expenses, the grants are recognized as a reduction of the related expense in the consolidated statements of income. For government grants related to reimbursements of capital expenditures, the grants are recognized as a reduction of the basis of the asset and recognized in the consolidated statements of income over the estimated useful life of the depreciable asset as reduced depreciation expense. See note 6.

(r) Reclassifications

A reclassification of $2,948 has been made between other income (expense) net and selling, administrative, and marketing on the consolidated statements of income for the year ended September 30, 2014 to conform to the September 30, 2015 presentation. A reclassification has been made between operating activities and investing activities on the consolidated statement of cash flows, related to the allowance for borrowed funds used during construction of $536 for the year ended September 30, 2014, to conform to the September 30, 2015 presentation.

(3) Rate Regulation and Regulatory Assets and Liabilities

(a) Rate Regulation

In April 2010, the VPSB approved an Alternative Regulation Plan for the Company (the Plan), effective October 1, 2010 through September 30, 2013. The acquisition of CVPS by NNEEC included the planned merger of CVPS into GMP, to create a single operating electric utility subsidiary of NNEEC, effective October 1, 2012. As part of the regulatory approval process for the acquisition, the Company proposed to amend GMP's Alternative Regulation Plan to extend the duration of the Plan for one year, through September 2014. The VPSB approved the proposed amendments to the Plan and extended the Plan through September 30, 2014.

The Plan contains the principal elements described below:

- A power supply cost adjustment mechanism (PSA) under which the Company recovers or credits to customers, on a quarterly basis, 90% of energy costs that are $615 (PSA Energy Cost Dead Band) per quarter higher or lower than energy costs included in rates and the full amount of transmission and capacity costs higher or lower than included in rates.

- An allowed rate of return on equity (ROE) of 9.58% in 2014. The allowed ROE under the Plan adjusts annually, up or down, at the rate of one-half of the change in the average 10-year Treasury Note rate, over a specified 20-day trading period. The ROE is further adjusted based on the Company's operational cost performance benchmarked against other utility companies, using a specified set of criteria based on historical FERC financial reports. Under the Plan, the Company has the ability to achieve up to 50 basis points of additional incremental ROE if the Company's ranking is within the top four (first quintile) of performance, and could lose up to 50 basis points of ROE if the Company's ranking is within the bottom four (last quintile) of performance.

- The Plan implements a synergies-savings plan approved by the VPSB as part of the merger of CVPS with and into GMP (the Merger), which includes providing customers with merger savings and fixes the combined companies' operations and maintenance expenses included in rates (the Base O&M Platform) for the purpose of measuring synergy savings over a 10-year period. Base O&M Platform expenses will be recovered in rates through 2022, increasing each rate year by the rate of inflation, based on the CPI N/E. See discussion below.

- An annual earnings sharing mechanism (ESAM) under which the Company has the opportunity to earn up to 75 basis points above its allowed ROE and to recover earning shortfalls in excess of 125 basis points below the allowed ROE (ESAM ROE Band). Under the Plan, certain exclusions, commonly made in setting rates, are applied to determine the Company's earnings and are expected to reduce the Company's ability to earn its allowed rate of return on equity for core utility operations.

- Base rates are adjusted annually, based on the Company's cost of service.

- The VPSB retains the authority to investigate the Company's rates at any time and to modify or terminate the Plan.

- Nonpower supply cost increases are capped at the amount currently allowed in rates, increased by inflation less a productivity factor of 1%, increased by a capital spending adjustment, adjusted for exogenous changes (if any) and further adjusted for any change in ROE. For 2015 and 2014, the formula that calculates the nonpower supply cost cap was higher than the requested rate increase; therefore, did not result in any disallowance. The productivity factor and ROE are subject to an incentive adjustment based on the Company's benchmarked performance against 20 other utility companies.

Under the Plan, the Company may recover extraordinary unforeseeable exogenous costs in excess of $1,200 (Exogenous Cost Threshold) per year.

As a condition of the VPSB's approval of the CVPS acquisition, the Company has agreed to a plan for sharing merger synergies with the following material elements:

- The Company is obligated to provide customers at least $144,000 (nominal dollars) in customer savings over 10 years: 2013 through 2022. Savings will be measured by comparing actual operating and maintenance (O&M) costs with the O&M Platform included in rates.
- In years 2013 through 2015, customer savings are fixed in the amounts of $2,500, $5,000 and $8,000, respectively.
- In 2016 through 2020, customers and the Company share synergy savings on a 50/50 basis.
- In 2021 through 2022, all synergy savings will be credited to customers.
- If total measured savings to customers are less than $144,000 after 2022, the Company shall provide the difference to retail customers by means of a Savings Guarantee Plan approved by the VPSB.

The Company has not recognized this obligation in its consolidated financial statements since it met the fiscal years 2015 and 2014 measures and expects that the total measured savings to customers will be achieved as described above.

In September 2013, the VPSB approved a 2.46% rate increase effective October 1, 2013 through September 30, 2014. The allowed return was 9.58%. Under a memorandum of understanding with the Vermont Public Service Department and approved by the VPSB, GMP deferred $4,910 of increased transmission costs in fiscal year 2014, to be recovered in fiscal year 2015. For the 2015 rate year, any rate increase shall be equal to the lower of 2.5% or the adjustment indicated by the 2015 revenue requirement, including the deferred $4,910 of expenses.

In August 2014, the VSPB approved a Successor Alternative Regulation Plan for the Company (the Successor Plan) effective October 1, 2014 through September 30, 2017. The Successor Plan maintains many of the features of the existing Plan but includes the following changes:

- The PSA Energy Costs Quarterly Dead Band was reduced from $615 to $307.
- The PSA is still accounted for on a quarterly basis but amounts to be recovered from or returned to customers occur at the time of the annual base rate adjustment and represent the 12-month period ending March 31.
- The Exogenous Cost Adjustment to be recovered from or returned to customers occurs at the time of the annual base rate adjustment and represents a 12-month period ending March 31.
- The ESAM ROE Band changed to allow the Company the opportunity to earn up to 35 basis points above the allowed ROE, to recover 50% of any earnings shortfall between 50 basis points and 200 basis points below the allowed ROE and to recover 100% of any earnings shortfalls in excess of 200 basis points below the allowed ROE.
- The ROE performance adjustment is eliminated.
- The allowed ROE for fiscal year 2015 is 9.6%.
- The $1,200 Exogenous Cost Threshold is adjusted for inflation based on the CPI-NE.
- Set rates for the Company's largest customer for three years.

In August 2014, the VPSB approved a 1.46% rate decrease effective October 1, 2014 through September 30, 2015. The VPSB also approved an additional 1.00% decrease returning to customers $5,960 of the Entergy

MOU funds. See note 19.

In September 2015, the VPSB approved a .73% rate increase consisting of a .08% base rate increase, a .67% exogenous adjustment increase and a .02% power adjustor decrease effective October 1, 2015 through September 30, 2016. The allowed ROE is 9.44%.

(b) Regulatory Assets and Liabilities

Regulatory assets and liabilities at September 30, 2015 and 2014 consist of the following:

		September 30, 2015	Amortizable 2015 balances included in rates	Original amortization period
Regulatory assets:				
Unfunded pension benefits	$	62,362	—	
Deferred storm costs		19,476	19,476	1 year
CEED fund		14,119	14,119	10 years
Pine Street Barge Canal costs		11,258	8,147	20 years
Deferred PSA Costs-undercollection		8,539	8,539	1 year
Meter retirements		6,721	6,721	5–6 years
Deferred efficiency fund		5,524	4,870	10 years
Income taxes		5,321	—	
Deferred nuclear outage costs		452	452	2 years
Asset retirement obligations (ARO)		340	340	18 years
Other regulatory assets		1,463	1,463	Various
Total regulatory assets		135,575	64,127	
Regulatory liabilities:				
Accumulated nonlegal costs of removal		36,365	—	
Power contract derivative	$	12,154	—	
VYNPC Revenue Sharing Agreement		8,888	8,888	1 year
Electricity assistance program		8,771	8,771	1–2 years
Millstone Unit #3 ARO		6,466	—	
DOE Settlement		2,334	2,334	1 year
Storm surcharge offset		1,731	1,731	2 years
VYNPC net unrealized gains on long-term investments		767	—	
Reserve for loss on power contract		299	299	11 years
Deferred PSA Revenues-overcollection		124	124	1 year
Other regulatory liabilities		1,085	—	
Total regulatory liabilities		78,984	22,147	
Net regulatory assets	$	56,591	41,980	
Regulatory assets classified as current	$	12,869		
Regulatory liabilities classified as current		16,101		

		September 30, 2014	Amortizable 2014 balances included in rates	Original amortization period
Regulatory assets:				
Unfunded pension benefits	$	52,932	—	
Pine Street Barge Canal costs		12,181	8,885	20 years
Meter retirements		8,983	8,983	5–6 years
Deferred transmission costs		4,910	4,910	1 year
Deferred storm costs		4,309	4,309	1 year
CEED fund		13,162	13,162	10 years
Derivative financial instruments		7,952	—	
Deferred efficiency fund		6,378	5,419	10 years
Income taxes		4,657	—	
Asset retirement obligations (ARO)		371	371	18 years
Other regulatory assets		1,513	1,090	Various
Total regulatory assets		117,348	47,129	
Regulatory liabilities:				
Accumulated nonlegal costs of removal		35,977	—	
Millstone Unit #3 ARO		6,631	—	
Overfunded postretirement benefits		4,281	—	
Reserve for loss on power contract		1,495	1,495	11 years
Electricity assistance program		7,019	7,019	1–2 years
VYNPC income tax valuation allowance reversal		2,101	2,101	1 year
DOE Settlement	$	2,764	2,764	1 year
Storm surcharge offset		1,637	—	
VYNPC net unrealized gains on long-term investments		957	—	
Other regulatory liabilities		1,135	227	Various
Total regulatory liabilities		63,997	13,606	
Net regulatory assets	$	53,351	33,523	
Regulatory assets classified as current	$	15,398		
Regulatory liabilities classified as current		10,472		

The table above indicates the pre-tax amount of net regulatory assets (liabilities) presently recorded. These amounts do not include the recognition of tax effects, which would be approximately 40.5%.

Unfunded Pension Benefits and Overfunded Postretirement Benefits

The pension and other postretirement benefit regulatory assets and liabilities reflected above represent the unrecognized pension costs and other postretirement benefit costs that would normally be recorded as a component of other comprehensive loss or income. Since these amounts represent costs or income that are expected to be included in future rates, they are recorded as regulatory assets or liabilities. Also included in the regulatory asset are other employee benefit costs that have been deferred for regulatory purposes. See note 13.

Deferred Storm Costs

Costs in excess of $1,200 allowed for exogenous factors, under the alternative regulation plan, may be recorded as a regulatory asset and recovered in future periods. At September 30, 2015 and 2014, deferred storm costs from major storms were $19,476 and $4,309, respectively, and the Company amortized $0 and $6,846 of storm costs during the years ended September 30, 2015 and 2014, respectively.

Community Energy and Efficiency Fund (CEED Fund)

One of the conditions associated with the VPSB approval of the acquisition of the former CVPS was that the Company create the CEED Fund. The CEED Fund is to be capitalized with an amount equal to approximately $21,000 (Required Investment) as of the date the VPSB approved the acquisition, June 15, 2012. Interest accrues at the rate of inflation on uninvested amounts until the Required Investment has been made. The Required Investment will be used to provide net customer benefits to customers in the former CVPS territory equal to or greater than 1.2 times the Required Investment or approximately $25,000 (Required Benefit).

The Company invested $10,000 in weatherization projects and has also invested an additional $5,000 in thermal and electric efficiency improvement projects. The remaining Required Investment must be made by June 2019. GMP has delivered approximately $24,000 in customer benefits as of September 2015. If the Company has not provided the Required Benefit by June 2019, the Company is required to file a plan for approval by the VPSB specifying how the remaining Required Benefit will be delivered. Any shortfall would be provided to the former CVPS customers on a uniform percentage basis in the form of a bill refund.

The Company's investments into the CEED fund are subject to VPSB approval and are included in rate base and recovered through rates over a 10-year period, beginning in fiscal year 2015. If additional investments in excess of the Required Investment are needed to deliver the Required Benefit such additional investments will not be recoverable through rates. The Company made total investments of $1,824 during 2015 and $5,105 during 2014 and recorded amortization of $866 in 2015 and $606 in 2014.

The VPSB approved the 2015 Plan authorizing investments of approximately $3,470 in primarily electric efficiency measures. The 2014 Plan authorized investments of approximately $2,100 of primarily electric efficiency measures. Additionally the PSB authorized an extension until December 31, 2014 to make previously approved thermal investments from the 2013 Annual Plan for the CEED fund.

Pine Street Barge Canal Costs

The Company has recorded a regulatory asset of $11,258 and $12,181 for the years ended September 30, 2015 and September 30, 2014, respectively, to reflect unrecovered past and future Pine Street Barge Canal costs, and will amortize the full amount of incurred costs over 20 years without a return. The past unrecovered costs regulatory asset of $8,147 is included in rates. The estimated future unrecovered cost regulatory asset of $3,111 has a matching liability and is not yet included in rates. The amortization of the regulatory asset is expected to be recovered in future rates. See note 17(b).

PSA over/Under-Collection

Under the Plan, a PSA under which the Company recovers or credits to customers, on a quarterly basis, 90% of energy costs that are $307 and $615 (per quarter) higher or lower than energy costs included in rates for

2015 and 2014 respectively, and the full amount of transmission and capacity costs higher or lower than included in rates.

As of September 30, 2015 and 2014, the Company recorded net deferred costs of $8,415 and net deferred revenues of $142, respectively, as a regulatory asset and regulatory liability, respectively. Deferred amounts are recovered from or credited to customers on an annual basis under the Successor Alternative Regulation Plan.

Meter Retirements

The Company has recorded a regulatory asset of $6,721 and $8,983 for the years ended September 30, 2015 and 2014, respectively, for old meters being replaced as a result of new technology related to the SmartPower implementation. The amount is being amortized over a 5 year period, commencing in the year ended September 30, 2013.

Deferred Efficiency Fund

One of the conditions associated with VPSB approval of the 2007 acquisition of GMP by NNEEC (2007 acquisition) was that the Company agreed to create an Efficiency Fund (EF) and an income-based discount program that would be capitalized with an amount of $8,000, adjusted for inflation since 2001. As of September 30, 2015 and 2014, the total regulatory assets recorded were $5,524 and $6,378, respectively. The EF permits customers to seek reimbursement for approved projects meeting certain energy conservation requirements. The income-based discount program was available for qualified customers to help pay for utility services in 2007 through 2009. As future amounts are expended by the Company, they become eligible to be recovered in rates. Management believes that expended amounts are probable of recovery.

Income Taxes

A regulatory asset or liability is established if it is probable that a future increase or decrease in income taxes payable will be recovered from or returned to customers through future rates. Income tax regulatory assets and liabilities have been established for the equity component of the allowance for funds used during construction, federal and state changes in enacted tax rates, if any, and for federal investment tax credits. These income tax regulatory assets and liabilities are combined into a net income tax regulatory asset.

Deferred Nuclear Outage Costs

Incremental costs associated with the scheduled refueling outage at Millstone Unit#3 nuclear plant are deferred and amortized over the period between scheduled outages.

Asset Retirement Obligations

The amount represents the deferred costs expected to be recognized in future rates, associated with conditional asset retirement obligations. Conditional asset retirement obligations are legal obligations to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Thus, the timing and/or method of settlement may be conditional on a future event. The Company amortizes amounts over periods similar to associated long lived assets included in utility plant.

Deferred Transmission Costs

The 2015 base rate filing approved recovery of these costs during fiscal 2015.

Other Regulatory Assets

Other regulatory assets consist of regulatory deferrals of hydro repowerment costs, costs associated with the Vermont Marble Value Sharing agreement and various other projects and deferrals that the Company expects to be recovered in future rates.

Accumulated Non-Legal Costs of Removal

Accumulated nonlegal costs of removal represent removal costs previously recovered from ratepayers for other-than-legal obligations. The Company reflects these amounts as a regulatory liability. The Company expects, over time, to recover or settle through future revenues any over – or under-collected net costs of removal.

Derivative Financial Instrument

The derivative financial instrument regulatory liability represents the fair value of certain power supply derivative assets that are expected to be recognized in future rates as the derivative contracts are settled. Settlement gains or losses related to the derivative contracts are returned to or fully recovered from customers in the rates the Company charges and are discussed in detail in note 14.

VYNPC Revenue Sharing Agreement

GMP received its share of the Entergy MOU payment in 2015 (see Note 19), and returned $5,900 to customers in 2015. GMP will apply $7,900 to deferred 2015 storm costs in accordance with the approved 2016 retail rate filing. This regulatory liability accrues interest until it is returned to customers.

Electricity Assistance Program

The Vermont Legislature passed a law in 2009 authorizing the VPSB to implement low income rates. GMP implemented an Electricity Assistance Program (EAP) in 2013 that provides financial assistance to qualified low-income residential customers. The program is funded by a per meter charge to all retail customers, and incurs costs for a 25% discount to eligible customers, and incremental costs for program administration. The regulatory liability balance represents the excess of the amount collected and costs incurred to date. In August 2015 the VPSB approved GMP's proposal for use of these funds that earmarks $450 for a rolling arrearage forgiveness program, returns $6,300 to customers in October 2015 and reduces the per meter charge collected from all retail customers by 33% effective in October 2015. In June 2014, the VPSB approved GMP's proposal for use of these excess funds that earmarked $1,000 to improve enrollment in the EAP and returned $1,500 to customers by December 31, 2014.

Millstone Unit #3 ARO

The Company has legal asset retirement obligations for decommissioning related to its jointly owned nuclear plant, Millstone Unit #3, and has an external trust fund dedicated to funding its share of future costs. This regulatory liability represents the excess of the decommissioning trust fund asset balance over the asset retirement obligation for decommissioning. The plant is currently operating and the ultimate decommissioning cost is an estimate at this time. The liability balance will be decreased when the forecasted decommissioning obligation exceeds the trust fund asset, resulting in a regulatory asset or returned to customers when the plant is fully decommissioned.

DOE Settlements

In June 2014, GMP received $5,700 for its share of the Phase 2 DOE settlements with Yankee Atomic, Connecticut Yankee, and Maine Yankee for the government's breach of contract to take the companies' spent fuel storage. In September 2014, GMP received $500 for its share of the Phase 1 DOE settlement. $3,500 of the settlements offset the fiscal year 2014 second quarter PSA under-collection. The remaining balance will be returned to customers in fiscal year 2016 as an offset against deferred storm costs. This regulatory liability accrues interest until it is returned to customers in future rate filings.

Storm Surcharge Offset

The remaining balance of the 2014 third quarter PSA over-collection of $1,637 was set aside to reduce the earnings sharing adjustment for 2015 storm costs. The storm costs, net of this liability, will be collected over 24 months beginning October 1, 2015. This regulatory liability accrues interest until it is returned to customers.

Reserve for Loss on Power Contract

In 2004, the Company established a reserve for a loss on a terminated power sales agreement in connection with the sale of a subsidiary's franchise. The reserve is being amortized on a straight-line basis through December 2015 as the cash is paid out under the underlying supply contracts. The amortization is being credited to power supply expense.

VYNPC Income Tax Valuation Allowance Reversal

The Company established a regulatory liability for the income tax benefit arising from acquiring 100% ownership interest and control of VYNPC. The amount was returned to ratepayers in fiscal year 2015, as approved in the 2015 base rate filing.

Other Regulatory Liabilities

Other regulatory liabilities consist of amounts received from VYNPC that are subject to a regulatory deferral order, and other insignificant amounts.

(4) Investments in Associated Companies

Investments in associated companies at September 30, 2015 and 2014 include the following:

	2015	
	Ownership interest	Investment in equity
VELCO – common	38.8%	$ 10,275
VELCO – preferred	80.1	190
Total VELCO		10,465
Transco LLC	69.1	424,859
Green Lantern Capital Solar Fund II, LP	99.9	1,037
New England Hydro Transmission – Common	3.2	174
New England Hydro Transmission Electric – Common	3.2	458
Connecticut Yankee Atomic Power Company	2.0	33
Maine Yankee Atomic Power Company	2.0	51
Yankee Atomic Electric Company	3.5	52
Total investment in associated companies		$ 437,129

	2014		
	Ownership interest		Investment in equity
VELCO – common	38.8%	$	10,179
VELCO – preferred	80.1		138
Total VELCO			10,317
Transco LLC	66.7		382,651
Green Lantern Capital Solar Fund II, LP	99.9		1,086
New England Hydro Transmission – Common	3.2		152
New England Hydro Transmission Electric – Common	3.2		367
Connecticut Yankee Atomic Power Company	2.0		32
Maine Yankee Atomic Power Company	2.0		48
Yankee Atomic Electric Company	3.5		53
Total investment in associated companies		$	394,706

(a) Vermont Electric Power Company and Vermont Transco LLC

VELCO and Transco own and operate the transmission system in Vermont over which bulk power is delivered to all electric utilities in the state. Transco owns the transmission assets comprising the system. Transco was formed by VELCO and VELCO's owners in 2006 and VELCO was appointed as the manager of Transco. On June 30, 2006, VELCO contributed substantially all of its operating assets to Transco, in exchange for 2,400 Class A Membership Units and Transco's assumption of VELCO's debt. Transco is governed by an Amended and Restated Operating Agreement (the Transco Operating Agreement) by and among VELCO, the Company and most of Vermont's other electric utilities. VELCO operates the Transco system under a Management Services Agreement with Transco. Transco is also governed by certain Amended and Restated Three-Party Agreements, assigned to Transco from VELCO, by and among the Company, VELCO and Transco, and VELCO remains subject to an Amended Four-Party Agreement among the Company and VELCO. VELCO currently has a 6.1% ownership interest in Transco. The remaining ownership interest in Transco is held by other Vermont-based utilities.

Pursuant to the merger agreement and VPSB order related to the acquisition of the former CVPS by NNEEC, CVPS transferred 38% of the total of VELCO Class B voting common stock and 31.7% of the total of VELCO Class C nonvoting common stock to Vermont Low Income Trust for Electricity, Inc. (VLITE), in June 2012. In addition, the transmission contracts, sponsor agreement and composition of the board of directors under which VELCO operates, effectively restrict the Company's ability to exercise control over VELCO.

The Company made capital investments of $27,221 and $23,252 in Transco in 2015 and 2014, respectively, to support various transmission projects. The Company receives its current rate of return (see note 3) on the investment in Transco, since the Transco investment is accounted for as a regulated business for Vermont rate-setting purposes. Capital contributions to Transco are based on the transmission cost share of the Vermont utilities. The Company and other taxable Transco owners, also receive additional earnings and distributions to compensate for differences in taxability with other nontaxable Transco owners.

Summarized unaudited financial information for Transco follows:

		Years ended September 30	
		2015	2014
Net income	$	80,688	76,059
Company's equity in net income		59,358	55,483
Total assets	$	1,037,394	993,993
Liabilities and long-term debt		444,718	441,538
Net assets	$	592,676	552,455
Company's equity in net assets	$	424,859	382,651

Transco provides transmission services to the Company and others pursuant to a transmission tariff known as the 1991 Transmission Agreement (the VTA), to which all Vermont electric utilities and the State of Vermont are parties. Under the VTA, the Company and all other Vermont utilities pay their pro rata share of Transco's total costs, including interest on debt and a fixed return on equity, less revenues collected by Transco under the ISO-New England Open Access Transmission Tariff and other agreements.

Transco provided transmission services to the Company (reflected as transmission expenses in the consolidated statements of income) amounting to $27,809 and $20,998 for the years ended September 30, 2015 and 2014, respectively.

In addition to its equity ownership interest in Transco, the Company also owns 38.8% of VELCO's common stock and 80.1% of its preferred stock. The Company's ownership interest in VELCO entitles it to approximately 38.8% of the dividends distributed by VELCO. The Company has recorded its equity in earnings on this basis.

The Transco Operating Agreement requires consent of the majority member (GMP) and a majority of the remaining ownership interests to remove Transco's manager (VELCO). Additionally, the structure of VELCO's board of directors prevents the Company from having a direct or indirect controlling financial interest in Transco; therefore, consolidation is not required.

Included in the Company's financial statements are construction service receipts of $723 and $524, billed to VELCO for the years ended September 30, 2015 and 2014, respectively.

Summarized unaudited financial information for VELCO (parent company only) is as follows:

		Years ended September 30	
		2015	2014
Net income	$	3,330	3,074
Company's equity in net income		1,203	1,292
Total assets	$	92,294	82,399
Liabilities and long-term debt		65,567	56,153
Net assets	$	26,727	26,246
Company's equity in net assets	$	10,465	10,317
Amounts due to VELCO, net		5,034	6,645

(b) Other Investments in Associated Companies

Green Lantern Capital Solar Fund II, LP: The Company is a limited partner of Green Lantern Capital Solar Fund II, LP (GLC) and has a 99.99% equity ownership interest. GLC was formed to finance solar power generating projects. The Company does not consolidate GLC as it does not control GLC. GLC is controlled by its general partner, Green Lantern Capital, LLC.

GMP's share of income from other associated companies not discussed in detail above totaled $176 and $142 during the years ended September 30, 2015 and 2014, respectively.

(5) Long-Term Investments

(a) Millstone Decommissioning Trust Fund

GMP has decommissioning trust fund investments related to its joint-ownership interest in Millstone Unit #3. The decommissioning trust fund was established pursuant to various federal and state guidelines. Among other requirements, the fund must be managed by an independent and prudent fund manager. Any gains or losses, realized and unrealized, are expected to be refunded to or collected from ratepayers and are recorded as regulatory assets or liabilities.

Regulatory authorities limit GMP's ability to oversee the day-to-day management of its nuclear decommissioning trust fund investments; therefore, GMP lacks investing ability and decision-making authority.

For the years ended September 30, 2015 and 2014, there were minimal realized gains and no realized losses. There were also no loss impairments of debt securities in 2015.

The fair values of these investments as of September 30, 2015 and 2014 are summarized below:

		2015	
		Amortized cost	Estimated fair value
Marketable equity securities	$	3,524	7,307
Marketable debt securities:			
Corporate bonds		450	463
U.S. government issued debt securities (agency and treasury)		1,048	1,085
State and municipal		90	94
Other			
Total marketable debt securities		1,588	1,642
Cash equivalents and other		36	36
Total	$	5,148	8,985

	2014	
	Amortized cost	Estimated fair value
Marketable equity securities	$ 3,396	7,380
Marketable debt securities:		
Corporate bonds	365	397
U.S. government issued debt securities (agency and treasury)	1,081	1,121
State and municipal	53	60
Other	—	—
Total marketable debt securities	1,499	1,578
Cash equivalents and other	50	50
Total	$ 4,945	9,008

The reported trust balances include net unrealized gains of $3,837 and $4,063 as of September 30, 2015 and 2014, respectively. The Company has recorded the corresponding adjustment as a regulatory liability.

Information related to the fair value and maturities of debt securities at September 30, 2015:

Within one year	$ 47
One to five years	512
Five to ten years	317
Over ten years	766
	$ 1,642

(6) Utility Plant

The major classes of utility plant are as follows:

	Depreciable life in years	September 30 2015	September 30 2014
Property, plant and equipment:			
Distribution	15-60	$ 726,835	695,082
Generation	35-110	480,389	448,185
Transmission	50-60	213,353	198,156
Intangible, FERC licenses and software	5-40	63,009	56,171
Buildings	50	45,047	40,253
General	10-30	22,519	20,542
Electric plant acquisition adjustments	11	22,951	22,951
Transportation	14	23,571	19,413
Office equipment	5–15	18,779	17,248
Transmission capital lease asset	30	—	1,779
Nuclear fuel, net	1–6	1,886	1,043
Total plant in service		1,618,339	1,520,823
Less accumulated depreciation and amortization		547,957	519,975
Net plant in service		1,070,382	1,000,848
Construction work in progress		40,369	62,798
Total utility plant, net		$ 1,110,751	1,063,646

Depreciation and amortization of utility plant in service totaled $36,105 and $9,257 and $38,909 and $8,135, respectively, for the years ended September 30, 2015 and 2014. During the years ended September 30, 2015 and 2014, administrative and general costs of $7,288 and $7,666, respectively, were capitalized, and there were no significant retirements. The composite depreciation rate for plant in service is 2.80% and 3.09%, respectively, for the years ended September 30, 2015 and 2014. The amount of CWIP included in rate base is $13,877 and $22,300, respectively, for the years ended September 30, 2015 and 2014.

Smart Grid Department of Energy Grant

In April 2010, GMP, the former CVPS and most other Vermont electric utilities received a grant of $69,000 from the DOE, as part of the U.S. federal government stimulus measures, to finance and implement a statewide smart electricity distribution system (Smart Grid). The grant requires a matching investment by the Vermont utility recipients and completion of grant related investments over a three-year period ending April 2013. The Company's share in the grant is $50,200, which equals the $50,200 investment by the Company, for a total Smart Grid investment of $100,400. The project consists of, among other activities, replacing GMP's current customer information system, installing technology to improve distribution system automation, purchasing and installing 272,500 advanced technology meters for customers, and participating in dynamic rates pilots with other electric utilities in Vermont. The Company began implementation in 2012 and completed the project in 2013. During the years ended September 30, 2015 and 2014, the Company received $0 and $3,206 from the DOE grant, of which $0 and $2,947, respectively, reduced the carrying cost of plant in service. No further grant receipts are expected from the DOE.

(7) Revolving Credit Facility

Effective December 15, 2014, GMP entered into a new $110,000 credit facility, with the ability to increase it by an additional $15,000, with KeyBank N.A. as the lead bank, replacing the existing $70,000 revolving line of credit.

The purpose of the facility is to provide liquidity for general corporate purposes, in the form of funds borrowed and letters of credit. The revolver is unsecured, and allows the Company to choose a rate based on a thirty (30) day LIBOR, Overnight LIBOR or the Alternative Base Rate plus the Applicable Rate (as defined in the revolver), with a margin based upon GMP's Standard and Poor's (S&P) unsecured credit rating of BBB+. The Overnight LIBOR rate at September 30, 2015 and 2014 was 1.22% and 1.58%, respectively and the 30 day LIBOR was 1.25% and 1.19%, respectively. The Company had $71,174 and $40,101 in cash borrowings, and $6,150 and $9,150 in letters of credit outstanding under its credit facility at September 30, 2015 and 2014, respectively. The Revolver balance has been classified as long term debt at September 30, 2015 and 2014, as the facility has a maturity date of December 14, 2019, and no annual requirement to pay off the outstanding balance on the credit facility. The Company was in compliance with all restrictive covenants and limitations as of September 30, 2015 and 2014.

(8) Long-Term Debt

Substantially all of the property and franchises of the Company are subject to the lien of the indentures under which the First Mortgage Bonds have been issued. The First Mortgage Bonds are callable at the Company's option at any time upon payment of a make-whole premium. The Company's long-term debt consists of the following:

		September 30	
		2015	2014
Total first mortgage bonds outstanding	$	592,905	600,120
Revolving line of credit		71,174	40,101
Total long-term debt outstanding		664,079	640,221
Less current maturities (due within one year)		7,240	7,215
Total first mortgage bonds outstanding, less current maturities	$	656,839	633,006
Weighted average interest rate on first mortgage bonds		5.54%	5.55%
Interest rate on revolving line of credit		1.24%	1.44%

The current corporate unsecured credit rating by S&P is BBB+; and the current senior secured debt credit ratings for the Company's first mortgage bonds by S&P is A. Amortization of capitalized bond issue expenses totaled $532 and $505 for the years ended September 30, 2015 and 2014, respectively.

GMP did not issue First Mortgage Bonds within the year ended September 30, 2015.

On December 16, 2013, the Company issued a total of $75,000 in First Mortgage Bonds under the 25th Supplemental Indenture in three separate series. The terms related to each series of bonds are customary and in line with the terms found within the Company's previous bond issuances. As in past bond issuances, the bonds include a provision for a "make-whole premium" which would apply if the Company called the bonds prior to maturity. Since there is a make-whole premium, there would be no detriment to the investor if the bonds were redeemed prior to maturity. Each series of bonds has a fixed interest rate, the bonds issued consisted of a $12,000 series with an interest rate of 4.07% which mature in 2029, a $20,000 series with an interest rate of 4.39% which mature in 2033 and a $43,000 series with an interest rate of 4.89% which mature in 2043.

The Company's long-term debt indentures and credit facility contain certain financial covenants. The most restrictive financial covenants include maximum debt to capitalization of 65% under its Indentures and 60% debt to capitalization requirements under the terms of our Vermont Economic Development Authority Recovery Zone Bonds. The Company was in compliance with all restrictive covenants and limitations as of September 30, 2015 and 2014.

The future maturities of long-term debt for each of the five years subsequent to September 30, 2015 are:

		Amount
Years ending September 30:		
2016	$	7,240
2017		7,255
2018		7,280
2019		86,300
2020		81,504
After 2021		474,500
Total	$	664,079

On September 29, 2015, the Company negotiated and set the interest rate for $50,000 in First Mortgage Bonds. The actual closing will not occur and the funds will not be received until December 2015. The bond pricing is $18,000 12-year maturity at a 3.31% coupon and $32,000 30-year maturity at a 4.26% coupon.

(9) Asset Retirement Obligations

(a) General

The Company continually reviews the regulations, laws, and contractual obligations such as decommissioning and easements to which it is a party to identify situations where there are legal obligations to perform asset retirement activities. Total asset retirement obligations were $7,825 and $7,460 at September 30, 2015 and 2014, respectively. Accretion expense was $227 and $220 for the years ended September 30, 2015 and 2014, respectively.

(b) Kingdom Community Winds (KCW)

The asset retirement obligations includes the accumulated liability of $3,732 and $3,551 at September 30, 2015 and 2014, respectively, for the decommissioning of the Company's wind facilities located on leased property. Related to this obligation, the Company has a letter of credit against its credit facility for $6,150. See note 6, 7, and 16.

(c) Millstone Unit #3

The asset retirement obligations include $2,519 for decommissioning related to the Company's joint-owned nuclear plant, Millstone Unit #3. See notes 3, 5, and 15 for further information.

(10) Other Liabilities and Deferred Credits

Other current and noncurrent liabilities at September 30, 2015 and 2014 are as follows:

		2015	2014
Other current liabilities:			
Health, insurance and damage reserves	$	6,627	6,200
Accrued taxes other than income		4,298	4,252
Cash concentration account – outstanding checks		3,477	3,932
Other		2,909	2,632
Accrued capital and O&M costs		1,925	1,509
SERP retirement benefits		479	564
VYNPC ENVY revenue sharing payment (See note 19)		—	17,896
Capital lease obligations		—	1,779
Deferred compensation		458	1,147
Total other current liabilities	$	20,173	39,911

		2015	2014
Other noncurrent liabilities and deferred credits:			
Accrued employee-related costs	$	1,088	1,189
Nuclear decommissioning		294	38
Other liabilities		380	316
Total other noncurrent liabilities and deferred credits	$	1,762	1,543

(a) Capital Lease – Obligations under Transmission Interconnection Support Agreement

Agreements executed in 1985 among the GMP, VELCO, and other New England Power Pool (NEPOOL) members and Hydro-Québec (HQ) provided for the construction of the second phase (Phase II) of the interconnection between the New England electric systems and that of HQ. Phase II provides 2,000 megawatts of capacity for transmission of HQ power to Sandy Pond, Massachusetts. Construction of Phase II commenced in 1988 and was completed in late 1990. The Company is entitled to 8.3% of the Phase II power supply benefits. Total construction costs for Phase II were approximately $380,000. 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 30-year agreements. At September 30, 2015 and 2014, the present value of the Company's obligation under the support agreements was $0 and $1,779, respectively, including a current obligation of $0 and $1,779, respectively. The obligation expired in 2015.

At September 30, 2015 and 2014 property under capital lease was comprised of $0 and $31,422 of original cost less $0 and $29,780, respectively, of accumulated amortization. Capital lease amortization totaled $1,779 and $1,253 for the years ended September 30, 2015 and 2014, respectively.

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% of the equity of the corporations owning the Phase II facilities and accounts for its ownership under the equity method of accounting. See note 4.

(11) Stockholder's Equity

(a) ***Appropriated Retained Earnings***

The Company had appropriated retained earnings of $787 and $784 at September 30, 2015 and 2014, respectively, relating to regulatory requirements arising from ownership of hydroelectric facilities.

(b) ***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, $99,593 and $70,162 of retained earnings were free of restrictions at September 30, 2015 and 2014, respectively.

Certain restrictions on the payment of cash dividends on common stock exist as a result of conditions of the VPSB's approval of the 2007 acquisition of the Company and the approval of the merger between the Company and CVPS. The Company is required to notify the VPSB of any changes that result in a 3% or greater change in capital structure from the structure approved in the Company's last rate proceeding. The Company is also required to provide notice within 10 days after declaring each regular common stock cash dividend and to provide 30-day advance notice before declaring any special cash dividend.

During the years ended September 30, 2015 and 2014, the Company provided notices related to regular common stock cash dividends. During 2014, the Company provided a notice related to a total special dividend of $22,500.

(c) ***Capital Contributions***

In the years ended September 30, 2015 and 2014, the Company received a $6,000 and $666, respectively, capital contribution from its parent, NNEEC. The primary purpose of the investment was to fund investments in utility plant and affiliates.

(d) ***Accumulated Other Comprehensive Income (Loss) (AOCI)***

The after-tax components of AOCL include the Company's equity share of changes in fair value of VELCO's interest rate swap derivative instrument.

(12) Income Taxes

The provision for income taxes for the years ended September 30, 2015 and 2014 is summarized as follows:

	2015	2014
Current federal income taxes	$ 44	(365)
Current state income taxes	102	46
Total current income taxes	146	(319)
Deferred federal income taxes	26,498	27,848
Deferred state income taxes	8,128	8,383
Total deferred income taxes	34,626	36,231
Investment tax credits-net	(280)	(352)
Income tax expense	$ 34,492	35,560

The significant items that reconcile between income taxes computed by applying the U.S. federal statutory rate and the reported income tax expense (benefit), for the reporting period, include the dividends received deduction, amortization of investment tax credits, energy credits, corporate owned life insurance and state income tax.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at September 30, 2015 and 2014 are presented below:

		2015	2014
Deferred tax assets:			
Customer advances for construction	$	4,186	4,171
Net operating losses and tax credits		57,795	40,952
Accumulated costs of removal		15,618	15,536
Deferred compensation and other benefit plans		24,285	22,312
Other liabilities and deferred credits		14,317	15,473
Derivative financial instruments		4,925	3,222
Total deferred tax assets	$	121,126	101,666
Deferred tax liabilities:			
Accelerated tax depreciation on property	$	249,716	219,670
Regulatory assets – pension and other postretirement benefits		25,065	22,683
Pine Street Barge Canal		14,655	5,347
Investment in associated companies		98,307	85,433
Other deferred charges and other assets		17,399	19,814
Nonutility subsidiary investment in wind farm		5,698	5,087
Derivative financial instrument regulatory assets		4,925	3,222
Total deferred tax liabilities	$	415,765	361,256
Net deferred income tax liability	$	294,639	259,590
Deferred income tax asset		24,727	20,704
Deferred income tax liability		319,366	280,294

The change in the net deferred tax liability arises from the deferred income tax expense included in the consolidated financial statements for the periods presented, primarily affected by accelerated tax depreciation, tax versus book differences in investment in affiliates, and changes in regulatory assets and liabilities.

As of September 30, 2015 GMP recorded $57,795 of deferred tax assets related to net operating loss (NOL) carryforwards and tax credit carryforwards. Federal NOLs will expire if unused starting in fiscal year 2033 and ending in fiscal year 2034. State NOLs will expire if unused starting in fiscal year 2019 and ending in fiscal year 2023. Management believes it is more likely than not that the Company will realize its deferred tax assets based upon the expected future reversals of taxable temporary differences and the generation of future taxable income. Based on these sources of future income the Company has not recorded any valuation allowances as of September 30, 2015 and 2014.

The Company records the benefits of investment tax credits through the amortization, as approved by the VPSB, of the unamortized investment tax credits, which are initially recorded as a liability. The remaining balance of unamortized investment tax credits shown separately on the consolidated balance sheets at September 30, 2015 and 2014 was $3,615 and $3,572, respectively.

While the Company believes it has adequately provided for all tax positions, amounts asserted by taxing authorities could be greater than the Company's accrued position. Accordingly, additional provisions on federal and state tax-related matters could be recorded in the future as revised estimates are made or the underlying matters are settled or otherwise resolved. During the year ended September 30, 2015, a charge of $54 was recorded for a reserve for unrecognized tax benefits relating to a fiscal year 2013 state income tax refund denied by the state. This issue is currently under appeal. Unrecognized tax benefits relating to a state net operating loss carryforward calculation were $272 at September 30, 2015 and 2014. During the year ended September 30, 2015, the Company reversed the unrecognized tax benefits reserve of $85 relating to VEBA trusts that was recorded during the year ended September 30, 2014. The VEBA issue has been settled through adjustments to the fiscal year 2014 beginning net operating loss carryforward balance in accordance with the Company's representations made to the Internal Revenue Service.

The Company recognizes interest accrued related to unrecognized tax benefits in interest expense and penalties in non-operating expenses. During the year ended September 30, 2015, the Company recognized income of approximately $389 resulting primarily from the reversal of interest and penalties accrued for the VEBA issue during the year ended September 30, 2014. During the year ended September 30, 2014, the Company recognized $421 in interest and penalties. The Company had approximately $64 and $454 accrued for the payment of interest and penalties at September 30, 2015 and 2014, respectively.

The Company is subject to income taxes in the United States, but no foreign jurisdictions.

At September 30, 2015, open tax years for federal and state tax returns are 2012 and forward. There were no federal tax audits during the years ended September 30, 2015 or 2014.

(13) Employee Benefit Plans

(a) Defined Benefit Pension Plan and Other Postretirement Benefit Plan

The Company has a qualified noncontributory defined benefit pension plan (the Pension Plan) covering substantially all of its employees. New employees are not eligible to participate in the defined benefit plans. The defined pension 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 receive a pension benefit when they are at least age 55 with a minimum of 10 years of service or when their combined years of service and age total 80 or 85 for GMP or the former CVPS plans, respectively. Normal retirement age is 65. The Company makes annual contributions to the plans up to the maximum amount that can be deducted for income tax purposes.

The Company also provides certain healthcare and life insurance benefits for retired employees and their dependents. Employees become eligible for these benefits if they reach retirement age while working for the Company. Eligibility and benefit levels vary depending on date of hire and whether or not the retiree was a CVPS employee prior to the merger with GMP. GMP employees hired after December 31, 2007 are not eligible to receive post-retirement health care benefits. The Company accrues the cost of these benefits during the service life of covered employees.

Postretirement healthcare benefits are recovered in rates. GMP amended its postretirement healthcare plan to establish a 401(h) sub account and separate Voluntary Employee Benefit Account (VEBA) trusts for its union and nonunion employees, for purposes of funding the plan benefits. The VEBA and 401(h) plan assets consist primarily of cash equivalent funds, fixed income securities and equity securities.

At September 30, 2015 and 2014, the unfunded pension obligations totaled $45,980 and $35,073, respectively. The Company recorded an offsetting regulatory asset for the net actuarial loss in the pension plan. At September 30, 2015, the other postretirement benefit obligation totaled $1,386, consisting of $210 included in Other current liabilities and $1,176 included in Unfunded pension and postretirement obligations on the consolidated balance sheets. At September 30, 2014, the other postretirement benefit prepayment totaled $3,484 and was included in Other assets on the consolidated balance sheets. At September 30, 2015 and 2014, the Company recorded an offsetting regulatory asset and regulatory liability, respectively, for the 2015 net actuarial loss and 2014 net actuarial gain in the postretirement benefit plan.

The following provides a summary of activity affecting the pension and postretirement plans' benefit obligations and assets for the years ended September 30, 2015 and 2014:

		2015	
		Pension plan benefits	**Other postretirement benefits**
Fair value of plan assets	$	172,121	39,557
Projected benefit obligation		218,101	40,943
Funded status	$	(45,980)	(1,386)
Accumulated benefit obligation	$	195,506	40,943
Net actuarial loss recognized in regulatory assets		59,869	897

		2014	
		Pension plan benefits	**Other postretirement benefits**
Fair value of plan assets	$	179,427	42,770
Projected benefit obligation		214,500	39,286
Funded status	$	(35,073)	3,484
Accumulated benefit obligation	$	190,790	39,286
Net actuarial loss (gain) recognized in regulatory assets (liabilities)		50,310	(4,281)

The Company pays for certain postretirement healthcare and life insurance benefits and those payments are included in the determination of the projected benefit obligation.

Net periodic pension expense and other postretirement benefit costs, employer and participant contributions, and benefits paid by plan are:

		2015		2014	
		Pension plan benefits	Other postretirement benefits	Pension plan benefits	Other postretirement benefits
Net periodic benefit cost	$	5,776	(158)	8,370	(83)
Employer contributions		4,428	381	8,536	—
Participant contributions		—	1,035	—	1,090
Benefits paid		11,885	3,719	27,018	3,453

GMP experienced a significant number of pension lump sum payouts in December 2013 which triggered settlement accounting and a pension re-measurement as of December 31, 2013. The re-measurement resulted in the Company recognizing additional pension cost of $3,649 in the year ended September 30, 2014.

Assumptions used to determine the Company's pension and postretirement benefit obligations were:

	Year ended September 30, 2015	
	Pension plan benefits	Other postretirement benefits
Weighted average assumptions as of year end:		
Discount rate	4.45%	4.30%
Expected return on assets	6.85	6.65
Rate of compensation increase	3.25	—
Current year healthcare cost trend	—	7.00
Ultimate year healthcare cost trend	—	5.00
Year of ultimate trend rate	—	2023

	Year ended September 30, 2014	
	Pension plan benefits	Other postretirement benefits
Weighted average assumptions as of year end:		
Discount rate	4.35%	4.20%
Expected return on assets	6.85	6.65
Rate of compensation increase	3.25	—
Current year healthcare cost trend	—	7.00
Ultimate year healthcare cost trend	—	5.00
Year of ultimate trend rate	—	2019

Assumptions used to determine the Company's pension and postretirement benefit costs were:

	Year ended September 30, 2015	
	Pension plan benefits	**Other postretirement benefits**
Weighted average assumptions as of year end:		
Discount rate	4.35%	4.20%
Expected return on plan assets	6.85	6.65
Rate of compensation increase	3.25	—
Current year healthcare cost trend	—	7.0
Ultimate year healthcare cost trend	—	5.0
Year of ultimate trend	—	2019

	Year ended September 30, 2014	
	Pension plan benefits	**Other postretirement benefits**
Weighted average assumptions as of year end:		
Discount rate	4.95%	4.70%
Expected return on plan assets	6.85	6.65
Rate of compensation increase	3.25	—
Current year healthcare cost trend	—	7.5
Ultimate year healthcare cost trend	—	5.0
Year of ultimate trend	—	2019

The mortality assumption utilized a RP-2006 generational mortality table with a projected improvement scale BB-2D and a RP-2000 generational mortality table with a projected improvement scale AA for the years ended September 30, 2015 and 2014, respectively.

For measurement purposes, a 7.0% annual rate of increase in the per capita cost of covered medical benefits was assumed for 2015 and 2014. This rate of increase was assumed to gradually decline to 5.0% in 2023 and 2019 for 2015 and 2014, respectively. The medical trend rate assumption has a significant effect on the amounts reported. For example, increasing the assumed healthcare cost trend rate by one percentage point for all future years would increase the total of the service and interest cost components of net periodic postretirement cost for the years ended September 30, 2015 and 2014 by $160 or 6.7% and $188 or 7.7%, respectively. Decreasing the trend rate by one percentage point for all future years would decrease the total of the service and interest cost components of net periodic postretirement cost for the years ended September 30, 2015 and 2014 by $126 or 5.3% and $148 or 6.1%, respectively. Increasing the assumed healthcare cost trend rate by one percentage point for all future years would increase the postretirement benefit obligation for the years ended September 30, 2015 and 2014 by $3,134 or 7.7% and $2,735 or 7.0%, respectively. Decreasing the trend rate by one percentage point for all future years would decrease the postretirement benefit obligation for the years ended September 30, 2015 and 2014 by $2,548 or 6.2% and $2,233 or 5.7%, respectively.

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 that 40% of combined plan assets be invested in equity securities, 42% of combined plan assets be invested in debt securities, and the remainder be invested in alternative and other investments.

For September 30, 2015 and 2014 the Company expects an annual long-term return of 6.85% for the pension plan assets and a 6.65% return for the other postretirement plan assets based on a representative 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 over the next 10 years.

Asset categories and weighted average allocation percentages are provided in the following table.

	Pension plan assets		Other postretirement benefit assets	
	2015	2014	2015	2014
Weighted average asset allocation asset category:				
Equity securities	38%	39%	65%	65%
Debt securities	47	42	35	33
Other	15	19	—	2
Total	100%	100%	100%	100%

(b) ***Pension and Postretirement Benefit Plans Asset Fair Values***

The fair values of the pension and other postretirement benefit plan investments are presented below:

Pension plan assets fair value measurements at September 30, 2015

	Total	Quoted prices in active markets for identical assets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Asset category:				
Cash equivalents	$ 3,782	3,782	—	—
Limited partnerships	26,327			26,327
Exchange traded funds	31,326	31,326	—	—
Equity securities:				
U.S. companies	18,826	18,720	—	106
International companies	2,063	1,214	849	—
Fixed income securities:				
U.S. Treasury securities	23,201	—	23,201	—
Mortgage-backed securities	19,188	—	19,188	—
Corporate Bonds-U.S. Companies	28,299	—	28,299	—
Corporate Bonds-Foreign	4,876	—	4,876	—
Municipal Bonds	1,913	—	1,913	—
Mutual funds:				
Equity funds	$ 12,320	12,320	—	—
Fixed-income funds	—	—	—	—
Real estate funds	—	—	—	—
Total	$ 172,121	67,362	78,326	26,433

	Pension plan assets fair value measurements at September 30, 2014			
	Total	Quoted prices in active markets for identical assets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Asset category:				
Cash equivalents	$ 5,401	5,401	—	—
Limited partnerships	21,458	—	—	21,458
Exchange traded funds	41,870	41,870	—	—
Equity securities:				
U.S. companies	14,029	13,891	—	138
International companies	2,399	1,462	937	—
Fixed income securities:				
U.S. Treasury securities	24,158	—	24,158	—
Mortgage-backed securities	13,744	—	13,744	—
Corporate Bonds-U.S. Companies	29,131	—	29,131	—
Corporate Bonds-Foreign	5,887	—	5,887	—
Municipal Bonds	1,787	—	1,787	—
Mutual funds:				
Equity funds	$ 18,209	18,209	—	—
Fixed-income funds	1,331	1,331	—	—
Real estate funds	23	—	—	23
Total	$ 179,427	82,164	75,644	21,619

		Other postretirement benefit plan assets fair value measurements at September 30, 2015			
		Total	Quoted prices in active markets for identical assets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Asset category:					
Cash equivalents	$	820	820	—	—
Exchange traded funds		7,718	7,718	—	—
Equity securities:					
U.S. companies		4,225	4,225	—	—
International companies		104	104	—	—
Fixed income securities:					
Corporate bonds		—	—	—	—
Mutual funds:					
Equity funds		15,014	15,014	—	—
Fixed-income funds		13,686	13,686	—	—
Real estate funds		10			10
Total	$	41,577	41,567	—	10
Less payable for future reimbursement at September 30, 2015		(2,020)			
Net plan assets	$	39,557			

	Other postretirement benefit plan assets fair value measurements at September 30, 2014			
	Total	Quoted prices in active markets for identical assets (Level 1)	Significant observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Asset category:				
Cash equivalents	$ 911	911	—	—
Exchange traded funds	8,465	8,465	—	—
Equity securities:				
U.S. companies	4,423	4,423	—	—
International companies	58	58	—	—
Fixed income securities:				
Corporate bonds	6	—	6	—
Mutual funds:				
Equity funds	15,791	15,791	—	—
Fixed-income funds	14,271	14,271	—	—
Real estate funds	29	—	—	29
Total	$ 43,954	43,919	6	29
Less payable for future reimbursement at September 30, 2014	(1,184)			
Net plan assets	$ 42,770			

Investments included in Level 3 primarily consist of the Plan's ownership in alternative investments; principally limited partnership interests in hedge, private equity, real estate, and other similar funds. Changes in the net fair value of pension and other postretirement benefit plan assets that are classified Level 3 are as follows:

	Years ended September 30	
	2015	2014
Balance at beginning of year	$ 21,648	21,753
Capital Contributions	8,275	—
Redemptions	(3,135)	—
Gains and losses (realized and unrealized)	(345)	(105)
Balance at end of year	$ 26,443	21,648

(c) ***Pension and Other Postretirement Benefit Plan Cash Flow***

Projected benefits and contributions are as follows:

	Pension plan Projected Contributions	Pension plan Projected Benefit payments	Other postretirement benefits Projected Contributions	Other postretirement benefits Projected Benefit payments
Years ending September 30:				
2016	$ 7,400	10,965	214	2,339
2017	—	11,253	—	2,344
2018	—	12,082	—	2,381
2019	—	12,678	—	2,425
2020	—	13,800	—	2,465
2021 through 2025	—	73,883	—	12,403

Pension and other postretirement contributions beyond 2016 have yet to be determined.

(d) Defined Contribution Plan

The Company maintains a 401(k) Savings Plan for substantially all employees. This plan provides for employee contributions up to specified limits. The Company matches employee pretax contributions up to 4%. The Company contributes an additional 0.75% for each year of eligible compensation made on a nonmatching basis to GMP employees hired prior to January 1, 2008 and to former CVPS employees hired prior to April 1, 2010. For GMP employees hired on or after January 1, 2008 and former CVPS employees hired on or after April 1, 2010, the Company contributes an additional 3.25% each year of eligible compensation, made on a nonmatching basis. The Company's matching contribution is immediately vested. The Company's matching and nonmatching contributions for the years ended September 30, 2015 and 2014 totaled $2,372 and $2,490, respectively.

(e) Supplemental Executive Retirement Plan

The Company provides a nonqualified retirement plan (SERP) for certain employees. Benefits under the SERP are funded on a cash basis. The amount of expense recognized for this plan for the years ended September 30, 2015 and 2014 was $794 and $668, respectively. As of September 30, 2015 and 2014, the SERP benefit obligation, based on a discount rate of 3.4% and 3.4%, was $4,702 and $5,869, respectively. As of September 30, 2015 and 2014, the current and long-term portions were $366 and $4,335 and $451 and $5,418, respectively. As of September 30, 2015 and 2014 regulatory assets were recorded for the unrecognized benefit costs associated with actuarial losses in the amount of $1,050 and $2,138, respectively.

GMP has life insurance policies intended to fund nonqualified SERP and deferred compensation benefits for GMP and former CVPS executives under the terms of their employment agreements. As of September 30, 2015 and 2014, the total cash surrender value was $20,229 and $20,734, of which $7,695 and $8,336, respectively, is included in a Rabbi Trust.

(f) Deferred Compensation

The Company has a deferred compensation plan for current and past officers and past directors. Amounts deferred are at the option of the officer or director, and include annual interest on the amounts deferred. As of September 30, 2015 and 2014 the obligations were $4,244 and $4,749, respectively.

VYNPC has a nonqualified 401(k) excess deferred compensation plan which is intended to provide additional retirement benefits for a select group of former management and highly compensated former employees. The total obligation was $1,647 and $1,822 at September 30, 2015 and 2014, respectively.

(14) Derivative Financial Instruments

The Company purchases the majority of its power supply, and uses long-term power supply contracts to mitigate rate volatility to ratepayers. The Company enters into physical power supply agreements with various counterparties to hedge against fossil fuel price increases. Many of these contracts are derivatives but because they meet the exception for a normal purchase and sale contract, they are not carried at fair value. See note 16.

The Company has recently entered into two capacity rate swap contracts to hedge a portion of its forward capacity costs. Since these contracts will settle on a net basis, they do not meet the criteria as a normal purchase and sale and they are accounted for at fair value. Additionally, the Company has determined that these capacity rate swap contracts are considered level 3 fair value measures since the valuation technique includes a significant unobservable assumption concerning the forward capacity market pricing curve. The Company had an agreement (the 9701 Agreement) that granted HQ an option to call power from the Company's power supply contract at prices below current and estimated future market rates. HQ has exercised all remaining call options under this agreement during 2015.

As a result the company records contract-specified prices for electricity as an expense in the period used, as opposed to the changes occurring in fair market values.

Due to a regulatory order from the VPSB that requires the Company to defer recognition of any earnings or other comprehensive income effects relating to future periods from power supply arrangements that qualify as derivatives, the Company records an offsetting regulatory asset or liability for the fair value of their derivative instruments. The current portion of derivative assets and liabilities, if any, are presented separately in the consolidated balance sheets.

The following table shows the calculated fair value of the derivative contracts, reflecting the risk that the Company or the counterparty will not execute upon the arrangement. Actual value upon settlement may differ materially from the fair values shown below:

		September 30			
		2015		2014	
Derivatives		Fair value assets	Liabilities	Fair value assets	Liabilities
Capacity rate swaps	$	12,154	—	—	—
9701 agreement	$	—	—	—	(7,952)
Total power supply derivative asset (liability)	$	12,154	—	—	(7,952)
Current portion	$	—	—	—	(7,952)

The tables below present assumptions used to estimate the fair value of the derivative contracts at September 30, 2015 and 2014. The forward prices for electricity used in this analysis are based on current broker quotations for energy delivered to New England, and the forward capacity prices are based on the forward capacity auction price determined by ISO New England.

	September 30, 2015					
	Valuation model	Risk free interest rate	Price volatility		Average forward price/kW-Mo	Contracts expire
Capacity rate swaps	Net Present Value	.88% - 1.63%	n/a	$	9.55	2019-2021

	September 30, 2014					
	Valuation model	Risk free interest rate	Price volatility		Average forward price/MWh	Contract expires
9701 agreement	Black-Scholes	0.02%	23%–24%	$	186	2015

Certain of the Company's derivative instruments contain reciprocal provisions that require the counter parties' and the Company's debt to maintain an investment grade credit rating from the major credit rating agencies. The failure to maintain an investment grade rating would obligate the counterparties or Company to deposit collateral in an amount equal to the fair value adjustment to the notional amount of the contract for derivative instruments in a liability position. A failure to maintain an investment grade rating would not obligate the counterparties or Company to deposit collateral at September 30, 2015 since there are no derivative liabilities at that date, and the capacity rate swap contracts are exempt from collateral provisions.

The following table summarizes the counterparties to GMP's derivative contracts together with the fair value of those contracts, if any, as of September 30, 2015 and 2014:

		2015			
		Market value			Collateral required if below investment grade
Counterparties		Risk free	With credit risk	Assets	
Next Era	$	12,477	12,154	12,154	—

		2014			
		Market value			Collateral required if below investment grade
Counterparties		Risk free	With credit risk	Liabilities	
Hydro-Québec	$	(7,963)	(7,952)	(7,952)	7,952

The Company recorded corresponding regulatory liabilities and assets. Amounts due during the next fiscal year are classified in current assets and current liabilities.

(15) Fair Value of Financial Instruments

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. The carrying amounts for cash and cash equivalents, accounts receivable, prepaid expenses, income tax receivable, accounts payable and accrued liabilities approximate their fair values because of their short-term maturities. The carrying amount of the spent fuel disposal fee and accrued interest obligation approximates its fair value because it represents the amount that would be required to be paid if the DOE was to begin taking delivery of spent nuclear fuel. See note 5(a). The fair value of the Company's revolving line of credit included in long-term debt approximates its carrying value due to the short-term nature of the related borrowings and the variable interest rate. Life insurance policies held by the Rabbi Trust are carried at cash surrender value.

The Company's estimates of fair value of financial assets and financial liabilities are based on the framework and hierarchy established in applicable accounting pronouncements. The framework is based on the inputs used in valuation, gives the highest priority to quoted prices in active markets and requires that observable inputs be used in the valuations when available. The disclosure of fair value estimates in the hierarchy is based on whether the significant inputs into the valuation are observable.

At September 30, 2015 and 2014, the fair value of the Company's first mortgage bonds included in long-term debt was $697,593 and $702,257 (carrying amount of $592,905 and $600,120), respectively. The fair value of the Company's first mortgage bonds are measured using quoted offered-side prices when quoted market prices are available. If quoted market prices are not available, the fair value is determined based on quoted market prices for similar issues with similar remaining time to maturity and similar credit ratings.

The following table sets forth by level the fair value hierarchy of financial assets and liabilities that are accounted for at fair value on a recurring basis. The Company's assessment of the significance of a particular input to the fair value measure requires judgment, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy:

	Fair value as of September 30, 2015			
	Level 1	Level 2	Level 3	Total
Assets:				
Derivatives - Capacity rate swaps	—	—	12,154	12,154
Total	$ —	—	12,154	12,154
Equity mutual funds				

	Fair value as of September 30, 2014			
	Level 1	Level 2	Level 3	Total
Liabilities:				
9701 agreement	$ —	7,952	—	7,952
Total	$ —	7,952	—	7,952

Millstone Decommissioning Trust

The Company's primary valuation technique to measure the fair value of its nuclear decommissioning trust investments is the market approach. GMP owns a share of the qualified decommissioning fund and cannot validate a publicly quoted price at the qualified fund level. However, actively traded quoted prices for the underlying securities in the fund have been obtained. Due to these observable inputs, fixed income, equity and cash equivalent securities in the qualified fund are classified as Level 2. Equity securities are held directly in GMP's nonqualified trust and actively traded quoted prices for these securities have been obtained. Due to these observable inputs, these equity securities are classified as Level 1.

At September 30, 2015, there were no recognized gains or losses included in earnings or other comprehensive income attributable to the change in unrealized gains or losses related to derivatives still held at the reporting date. This is due to the Company's regulatory accounting treatment for all power-related derivatives. The following table is a reconciliation of the changes in net fair value of capacity rate swap contracts that are classified as Level 3 in the fair value hierarchy:

Balance at beginning of period	$	—
Change in fair value relating to unrealized gains		12,154
Balance at September 30, 2015	$	12,154

(16) Long-Term Power Purchase and Other Commitments

(a) Electricity Purchase Commitments

Purchased power expense by significant contract supplier was as follows:

		Year ended September 30	
		2015	**2014**
Hydro Québec	$	108,020	103,411
Independent Power Producers		41,282	35,165
Nextera		40,592	21,267
JP Morgan		24,035	27,754
Granite Reliable		13,873	13,487
Citigroup		12,045	—
Exelon (formerly Constellation Energy)		—	27,358

These contracts qualify for normal purchases and sales treatment, and are not subject to fair value accounting treatment as they are for the purchase of electricity to fulfill the Company's power supply needs. The expense related to these contracts is recorded and recognized in power supply expense at the time that the contracts are settled and the Company takes delivery of the electricity.

Significant purchased power contracts in effect as of September 30, 2015, including estimates for the Company's portion of certain minimum costs, are as follows:

		Estimated payments contractually due
Years ending September 30:		
2016	$	180,851
2017		194,720
2018		190,391
2019		181,265
2020		161,708
Beyond 2020		2,054,585
Total	$	2,963,520

(b) Hydro-Québec Contracts

Under various contracts, the Company purchases capacity and associated energy produced by HQ. These 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. These minimum energy purchases must be made whether or not other less expensive energy sources might be available in the short-term market. These contracts are intended to complement the other components in the Company's power supply.

The Company currently purchases power pursuant to the Vermont Joint Owners (VJO) contract with HQ entered into in December 1987. The contract contains different schedules that expire between 2015 and 2021. If any VJO contract participant fails to meet its obligation under the VJO contract with HQ, the remaining contract participants, including the Company, will assume the defaulting participant's share on a prorated basis. To date there have been no defaults under the VJO contract.

To determine the "maximum potential" amount of future payments the Company could be required to make under its guarantee included in the VJO contract, the Company must assume that all other members of the VJO contract simultaneously default. The Company estimates that its undiscounted purchase obligation under the "step-up" provision would be $17,050 for the remainder of the contract, assuming that all other members of the VJO contract defaulted by September 30, 2015, 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 VJO contract participants, 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 on wholesale market prices at the time.

Under the VJO contract, HQ retains the right to curtail annual energy deliveries by 10% up to five times, over the 2001 to 2015 period, if documented drought conditions exist in Quebec. HQ has never curtailed GMP energy deliveries due to documented drought conditions.

Commencing April 1, 1998, and effective through October 2015, HQ can exercise an option to purchase up to 52,500 MW pursuant to the 9701 Agreement 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. Annually; HQ has exercised and received power for the 9701 Agreement option. The replacement cost of this power is amortized over the calendar year. Approximately $2,048 and $2,598 was amortized during the years ended September 30, 2015 and 2014.

On April 15, 2011, the VPSB approved a long-term power purchase and sale agreement between Hydro-Québec Energy Services (U.S.) Inc. (HQUS), a subsidiary of HQ, and a group of Vermont utilities including GMP. The Company determined that the contract qualifies for "normal purchase normal sale" accounting treatment. Under the HQUS agreement, GMP will receive a portion of a statewide total of up to 218 or 225 MW of energy, delivered in a fixed 16 hour/day (i.e., 7x16) profile, and a corresponding portion of the environmental attributes (such as, for example, credits, benefits or emissions reductions) associated with this power. Such environmental attributes must meet a requirement specifying a hydropower content of at least 90%. HQUS markets electricity from HQ's generating facilities, whose output is presently well in excess of 90% hydroelectric. The contract lays a foundation that will guarantee GMP continued access to a reliable supply of power from HQ facilities, which should help GMP to maintain its favorable carbon footprint. Deliveries under this purchase commenced on November 1, 2012 at very small volumes, and will increase substantially in 2016 (as the existing VJO contract is expiring), and end in 2038. In 2016, the energy volumes under the contract represent an estimated 18% of GMP's projected annual energy requirement, increasing to 22% in 2017 as the largest schedules under the existing VJO contract expire.

The new HQUS contract does not feature options for the buyer or seller to adjust the annual load factor of deliveries or a delivery curtailment option comparable to the 9701 option, and does not contain a step-up provision. The new HQUS contract does not include capacity, which must be purchased from other parties or left open to market prices.

The Company's contracts with HQ call for the delivery of system power and are not related to any particular facilities in the HQ system. Consequently, there are no identifiable debt-service charges associated with any particular HQ 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.

(c) ***System Energy Contracts***

The Company enters into system energy purchase contracts with various counterparties in the normal course of its business. The system contracts are usually less than five years in duration and call for firm physical delivery of specified hourly quantities that are not associated with any specific generation source and not subject to outage risk. The counter-parties are responsible for acquiring and taking title to the power that is purchased by the Company. The Company presently has in place several system energy purchases for deliveries through 2020, for terms from several months to 5 years.

(d) ***Other Renewable Power Contracts***

The Company has committed to several contracts to purchase output from new renewable power plants, some for periods of up to 20 years, on a plant-contingent basis (the Company receives and pays only for its share of quantities actually generated by the plant). These purchases typically include energy, capacity, and renewable energy certificates and are derived from wind or landfill gas plants. The largest such purchase is a 20-year contract with the Granite Reliable wind project in New Hampshire, which began in April 2012.

(e) ***Next Era Seabrook Purchase***

The Company agreed to purchase long-term energy, capacity and generation attributes from the Seabrook Nuclear Power Plant in New Hampshire owned by Next Era Seabrook LLC. This contract commenced in 2012 with purchases of approximately 131,000 MWh per year of System Power that is not related to any specific facility. Beginning in 2015, all purchases will be unit contingent purchases from the Seabrook Nuclear Power Plant beginning at 60MW, which will decrease to 50 MW and then to 40 MW over the life of the contract that ends in 2034.

(f) 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 included in "purchases from others" in the consolidated statements of income.

(g) Kingdom Community Wind

In October 2012, the Company completed construction and began daily commercial operation of the Kingdom Community Wind project (KCW) a 63-MW wind facility in Lowell. Eight MW of the project's output is being sold to Vermont Electric Cooperative, Inc. under a long-term contract. The remainder will be incorporated into the Company's power supply.

(h) Nuclear Decommissioning Obligations

VYNPC: VYNPC owned and operated a boiling water nuclear-powered generating plant (the Plant) in Vernon, Vermont until 2002, when it sold the Plant and related assets and liabilities to Entergy. When the Plant was sold to Entergy it was licensed to operate until March 21, 2012. In 2011, the Plant was granted a 20-year license extension by the Nuclear Regulatory Commission (NRC). Entergy had been working to address matters involving the State of Vermont to continue operating after March 21, 2012. On August 27, 2013, Entergy announced its plans to close and decommission the Plant and the Plant was shut down on December 29, 2014. Entergy assumed the obligation to decommission the Plant when it was sold to them; therefore, the Company has no obligation to decommission the Plant.

Financial obligations of VYNPC continue beyond March 21, 2012, including the one-time fee for the disposal of pre-1983 spent nuclear fuel, and retiree pension and benefits, which will be funded by GMP's investments in the spent fuel disposal trust, the Rabbi Trust, pension plan assets, and related investment income, and future payments from the Sponsors under the Power Contracts, which include GMP and several New England electric utilities.

VYNPC has a dedicated Trust Fund that meets most of the pre-1983 spent fuel liability. Changes in the underlying interest rates that affect the earnings and the liability could cause the balance to be a surplus or deficit. Excess funds, if any, will be returned to the Company and the other former owners and must be applied for the benefit of retail customers.

Millstone Unit #3: GMP is obligated to pay its share of nuclear decommissioning costs for nuclear plants in which it has an ownership interest. GMP has an external trust dedicated to funding its joint-ownership share of future Millstone Unit #3 decommissioning costs. Dominion Nuclear Connecticut has suspended contributions to the Millstone Unit #3 Trust Fund because the minimum NRC funding requirements have been met or exceeded. GMP also suspended contributions to the Trust Fund, but could choose to renew funding at its own discretion if the minimum requirement is met or exceeded. If a need for additional decommissioning funding is necessary, GMP will be obligated to resume contributions to the Trust Fund.

Other Yankee Companies: GMP has equity ownership interests in Maine Yankee, Connecticut Yankee and Yankee Atomic. These plants are permanently shut down and completely decommissioned except for the spent fuel storage at each location. The Company's obligations related to these plants are described in note 4. The balance of GMP's net nuclear decommissioning cost liability was $428 at September 30, 2015. The current and long-term portions of $133 and $295 are included in accounts payable, trade and accrued liabilities and other liabilities. The balance of GMP's net nuclear decommissioning cost liability was $171 at September 30, 2014. The current and long-term portions of $133 and $38 are included in accounts payable, trade and accrued liabilities and other liabilities.

(i) ***Jointly Owned Facilities***

GMP's joint-ownership interests in electric generating and transmission facilities as of September 30, 2015 and 2014 are as follows:

	2015			
	Ownership interest	Share of capacity (in MW)	Share of utility plant	Share of accumulated depreciation
Joseph C. McNeil	31.0%	16.7	$ 28,801	24,510
Wyman #4	2.9	17.6	6,321	5,704
Stony Brook #1	8.8	31.0	11,390	11,007
Highgate Transmission Facility	82.3	162.6	47,732	14,334
Metallic Neutral Return	59.4	—	1,563	1,501
Millstone Unit #3	1.7	21.4	81,966	46,581

	2014			
	Ownership interest	Share of capacity (in MW)	Share of utility plant	Share of accumulated depreciation
Joseph C. McNeil	31.0%	16.7	$ 29,440	24,158
Wyman #4	2.9	17.6	6,318	5,516
Stony Brook #1	8.8	31.0	11,598	10,875
Highgate Transmission Facility	82.3	162.6	46,276	13,523
Metallic Neutral Return	59.4	—	1,563	1,478
Millstone Unit #3	1.7	21.4	81,404	45,606

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

GMP's share of expenses for these facilities is included in operating expenses in the consolidated statements of income under the caption "Power supply expenses – Company-owned generation" for the listed generation plants (Wyman, Stony Brook, McNeil, and Millstone), under the caption "Transmission expenses" for the Metallic Neutral Return and Highgate facilities, and under the caption "Depreciation and amortization expenses" for all facilities. Each participant in these facilities must provide their own financing.

(j) ***Renewable Energy Credits***

During the years ended September 30, 2015 and 2014, the Company received $23,999 and $20,065, respectively, of net revenue from RECs. The Company's RECs for the years ended September 30, 2015 were approximately 17% from Granite Reliable, 9% from McNeil, 3% from Moretown, 42% from KCW and 29% from a variety of other sources. In the future, REC revenues may become less certain as Vermont and other states may adjust their renewable policies.

(k) ***Operating Leases***

Vehicle Leases: GMP had two master lease agreements for vehicles and related equipment. On October 30, 2009, former CVPS signed a vehicle lease agreement to finance many of the vehicles covered by a former agreement. As of September 30, 2015, the Company is no longer leasing vehicles under this agreement. The total acquisition costs of all leased property under this agreement as of September 30, 2015 and 2014 is $0 and $1,804, respectively.

On October 24, 2008, the former CVPS entered into an operating lease for new vehicles and other related equipment. The guarantee obligation under this lease is limited to 5% of the acquisition cost. The maximum amount of future payments under this guarantee as of September 30, 2015 is $102. The total future minimum lease payments required for all lease schedules under this agreement as of September 30, 2015 was $188. As of September 30, 2015 and 2014 there is no credit line in place for additions under this agreement. The total acquisition cost of all leased property under this agreement is $2,039 and $2,580 as of September 30, 2015 and 2014, respectively.

As of September 30, 2015, future minimum rental payments required under noncancelable operating vehicle leases are expected to total $188, consisting of $188 in 2016 and $0 for years thereafter.

Solar Leases: During the years ended September 30, 2015 and 2014, the Company entered into solar-related operating leases, which are primarily for leased land to host the Company's solar-related utility plant for solar power production and related activities.

The most significant lease is for land at a landfill site used to host a solar farm. The total minimum lease payments under this agreement are $780. As of September 30, 2015, future minimum rental payments required under all noncancelable operating solar leases are expected to total $902, consisting of $37 per year in 2016 through 2020 and $717 for years thereafter.

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

Total rental expense, which includes pole attachment rents in addition to the operating lease agreements described above, amounted to $2,894 and $3,620 for the years ended September 30, 2015 and 2014, respectively. These rental expenses are included in maintenance and other operating expenses on the consolidated statements of income.

(l) ***Other Commitments***

The Company is required to set aside $361 and $432 as of September 30, 2015 and 2014, respectively, for a rate phase-in agreement related to the acquisition of the Vermont Marble Power Division, and renewable generation development under a VPSB regulatory order. These amounts are included in the accompanying consolidated balance sheets in cash and cash equivalents.

(m) Iberdrola Renewables Agreement

In October 2015, The Company signed a twenty-five year purchase power agreement with Iberdrola Renewables to purchase 100% of the output from their 30 MW Deerfield wind facility being developed in southern Vermont. This contract is unit-contingent meaning that the Company only pays for the actual output of the plant that it receives, which included energy, capacity, and renewable energy certificates. Pending review by various Vermont state agencies, construction could begin in 2016 with commercial operation commencing in 2017.

(17) Environmental Matters

(a) General

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

(b) 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. As of September 30, 2015 the Company has estimated total costs of the Company's future obligations under the consent decree to be approximately $3,112, net of recoveries. The estimated liability is not discounted, and it is possible that the Company's estimate of future costs could change by a material amount. As of September 30, 2015 and 2014 the Company has recorded a regulatory asset of $11,258 and $12,181, respectively, to reflect unrecovered past and future Pine Street Barge Canal costs. Pursuant to the Company's 2003 Rate Plan, as approved by the VPSB, the Company began to amortize and recover these 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 current and future rates, without disallowance or adjustment, until fully amortized.

(c) Clean Power Plan

In August 2015, the United States Environmental Protection Agency issued a final rule for its proposed Clean Power Plan, which requires significant reductions in CO_2 emissions from existing power plants by 2030. 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 Clean Power Plan or proposals to make more stringent regulations under that legislation.

(d) Catamount Indemnifications

On December 20, 2005, the former CVPS completed the sale of Catamount, its wholly owned subsidiary, to CEC Wind Acquisition, LLC, a company established by Diamond Castle Holdings, a New York-based private equity investment firm. Under the terms of the agreements with Catamount and Diamond Castle Holdings, the former CVPS agreed to indemnify them, and certain of their respective affiliates, in respect of a breach of certain representations and warranties and covenants, most of which ended June 30, 2007, except certain items that customarily survive indefinitely. Environmental indemnifications are subject to a $1,500 deductible and a $15,000 cap, and such environmental representations for only two of Catamount's underlying energy projects survived beyond June 30, 2007. The Company has not recorded any liability related to these indemnifications. To management's knowledge, there is no pending or threatened litigation with the potential to cause material expense.

(18) Other Contingent Liabilities

(a) DOE Litigation – Maine Yankee, Connecticut Yankee and Yankee Atomic

All three companies have been seeking recovery of fuel storage-related costs stemming from the default of the DOE under the 1983 fuel disposal contracts that were mandated by the United States Congress under the Nuclear Waste Policy Act of 1982. Under the Act, the companies believe the DOE was required to begin removing spent nuclear fuel and greater than Class C waste from the nuclear plants no later than January 31, 1998 in return for payments by each company into the nuclear waste fund. No fuel or greater than Class C waste has been collected by the DOE, and each company's spent fuel is stored at its own site. Maine Yankee, Connecticut Yankee and Yankee Atomic collected the funds from GMP and other wholesale utility customers, under FERC-approved wholesale rates, and GMP's share of these payments was collected from their retail customers. The DOE decided not to appeal the decision to the U.S. Supreme Court and in February 2013 the federal government reimbursed the three companies for the Phase I damages. In June 2013, FERC established the process by which the litigation proceeds are credited and approved refunds through lower wholesale rates to utility customers, effective July 2013. GMP's share of the Phase I damages totaled approximately $3,767. Phase I includes damages for Connecticut Yankee and Yankee Atomic through 2001, and for Maine Yankee through 2002.

Phase II damages were ruled upon in November of 2013, and the DOE did not appeal. GMP's share of these funds, totaling $5,700, was received in June 2014.

A complaint for Phase III damages was filed in August 2013. A trial was held from June 30 through July 2, 2015, but the judge has not issued a decision.

Due to the complexity of these issues and the potential for further appeals, the three companies cannot predict the timing of the final determinations or the amount of damages that will actually be received. Each of the companies' respective FERC settlements requires that damage payments, net of taxes and further spent fuel trust funding, if any, be credited to wholesale ratepayers including GMP. The Company expects that its share of these awards, if any, would be credited to retail customers.

(b) Nuclear Insurance

The Price-Anderson Act provides a framework for immediate, no-fault insurance coverage for the public in the event of a nuclear power plant accident that is deemed an extraordinary nuclear occurrence by the NRC. The primary level provides liability insurance coverage of $375,000, or the maximum private insurance available. If this amount is not sufficient to cover claims arising from an accident, the second level applies offering additional coverage up to $13.2 billion per incident. For the second level, each operating nuclear plant must pay a retrospective premium equal to its proportionate share of the excess loss, up to a maximum of $127,300 per reactor per incident, limited to a maximum annual payout of $19,000 per reactor. These assessments will be adjusted for inflation and the U.S. Congress can modify or increase the insurance liability coverage limits at any time through legislation. Currently, based on the GMP's joint-ownership interest in Millstone Unit #3, the Company could become liable for expenses of approximately $328 of such maximum assessment per incident per year. Maine Yankee, Connecticut Yankee and Yankee Atomic maintain $100,000 in Nuclear Liability Insurance, but have received exemptions from participating in the secondary financial protection program.

(c) *Other Legal Matters*

The Company does not expect any litigation to result in a material adverse effect on its operating results or financial condition.

(19) Related-Party and Associated Company Transactions

Effective April 12, 2007, GMP became related to Vermont Gas Systems (VGS) when the Company was acquired by NNEEC. The rates at which the Company buys gas for facility heating from VGS and the rates at which VGS buys electricity from the Company are regulated and required to be transacted at rates approved by the VPSB, and applicable to similar customers of similar usage, and amounts are insignificant and immaterial with respect to these regulated revenues. VGS is also a responsible party in the Pine Street Barge Canal Superfund Site and remits funds related to this matter annually to the Company. Payments totaling $78 and $269 were received for the Pine Street Barge Canal Superfund Site during the years ended September 30, 2015 and 2014, respectively, and there were no other transactions between VGS and the Company during the years ended September 30, 2015 and 2014.

The following table summarizes account receivable and payable balances from and to affiliated companies.

		Accounts receivable	Accounts payable	Net receivable (payable)
At September 30, 2015:				
NNEEC		82	—	82
Connecticut Yankee Atomic Power Company	$	—	3	(3)
Maine Yankee Atomic Power Company		—	—	—
VELCO		71	5,105	(5,034)
Total	$	153	5,108	(4,955)

		Accounts receivable	Accounts payable	Net receivable (payable)
At September 30, 2014:				
NNEEC			22	(22)
Connecticut Yankee Atomic Power Company	$	—	3	(3)
Maine Yankee Atomic Power Company		—	1	(1)
VELCO		13	6,658	(6,645)
Total	$	13	6,684	(6,671)

(20) Concentration Risks

(a) *HQ and NextEra Power Supply Contracts*

The Company's material power supply contracts are principally with HQ and NextEra. HQ contracts are expected to meet from 21% to 24% of the Company's anticipated annual demand requirements through 2035.

Beginning in 2015, the Next Era contract representing unit contingent purchases from the Seabrook Nuclear Power Plant is at 60 MW and will decrease to 40 MW, and will meet between 7% and 12% of the Company's annual demand requirements over the life of the contract that ends in 2034. Under the Company's Alternative Regulation Plan, there is a power supply adjustment mechanism to minimize the risk of rising power supply costs.

(b) ***Number of Employees***

At September 30, 2015 and 2014, GMP had 569 and 604 employees, respectively. Of these employees, at September 30, 2015 and 2014, 291 and 296, respectively, were represented by Local Union No. 300, affiliated with the International Brotherhood of Electrical Workers. On January 14, 2013, the Company agreed to a new five-year contract with its employees represented by the union, which is effective on January 1, 2013 and expires on December 31, 2017.

(21) Supplemental Cash Flow Information

Supplemental cash flow information for the years ended September 30, 2015 and 2014 are as follows:

		2015	2014
Cash paid for:			
Interest	$	33,957	32,460
Income taxes paid, net		32	26
Supplemental disclosures of noncash information:			
Increase in unfunded pension and other postretirement benefit obligations		20,061	21,718
Plant addition for allowance for equity funds used during construction		1,199	965
Noncash utility plant in accounts payable		2,877	6,295
Note receivable issued for sale of property		—	65
Addition to capital lease assets and related obligation		—	533

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	79,010		79,010		
2					
3	17,563		17,563		
4	17,563		17,563	28,307,265	28,324,828
5	96,573		96,573		
6					
7					
8					
9				28,095,393	28,095,393
10					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	1,636,860,210	1,636,860,210
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	-4,605	-4,605
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,636,855,605	1,636,855,605
9	Leased to Others		
10	Held for Future Use	42,820	42,820
11	Construction Work in Progress	48,546,219	48,546,219
12	Acquisition Adjustments	22,951,227	22,951,227
13	Total Utility Plant (8 thru 12)	1,708,395,871	1,708,395,871
14	Accum Prov for Depr, Amort, & Depl	607,613,726	607,613,726
15	Net Utility Plant (13 less 14)	1,100,782,145	1,100,782,145
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	570,858,789	570,858,789
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	26,670,307	26,670,307
22	Total In Service (18 thru 21)	597,529,096	597,529,096
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	10,084,630	10,084,630
33	Total Accum Prov (equals 14) (22,26,30,31,32)	607,613,726	607,613,726

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 06/30/2016	Year/Period of Report End of 2016/Q2

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
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					29
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					32
					33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

ELECTRIC PLANT IN SERVICE AND ACCUMULATED PROVISION FOR DEPRECIATION BY FUNCTION

1. Report below the original cost of plant in service by function. In addition to Account 101, include Account 102, and Account 106. Report in column (b) the original cost of plant in service and in column(c) the accumulated provision for depreciation and amortization by function.

Line No.	Item (a)	Plant in Service Balance at End of Quarter (b)	Accumulated Depreciation and Amortization Balance at End of Quarter (c)
1	Intangible Plant	64,332,562	26,605,010
2	Steam Production Plant	34,353,435	30,698,921
3	Nuclear Production Plant	81,388,435	47,087,101
4	Hydraulic Production - Conventional	177,637,623	64,503,659
5	Hydraulic Production - Pumped Storage		
6	Other Production	194,093,374	52,493,445
7	Transmission	211,730,523	61,135,770
8	Distribution	758,454,372	283,903,909
9	Regional Transmission and Market Operation		
10	General	114,908,101	31,101,281
11	TOTAL (Total of lines 1 through 10)	1,636,898,425	597,529,096

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Lamoille River - SIS & SFS	1,665	235		
23	Wilder Solar - SIS	312	235	25,000	235
24	Hidden Meadow Solar - SIS	1,040	235		
25	Elizabeth Copper Mine - SIS	18,000	235		
26	Elizabeth Copper Mine - SFS	3,524	235		
27	TDI Clean Energy - SIS	10,220	235		
28	Grand Isle 400 - SIS	12,076	235		
29	Otter Creek Solar I - SFS	2,498	235		
30	Otter Creek Solar II- SFS	856	235		
31	Slang Creek - SIS	27,682	235		
32	Ampersand Gilman Solar - SIS	17,508	235		
33	Ampersand Gilman Solar - SFS	1,645	235	10,000	235
34	Swanton ISO - SIS	2,557	235		
35	Ryegate & Wells River - SIS	3,051	235	26,625	235
36	Nat Grid 74GI Ski Bowl - SIS			5,000	235
37	SBVT Landfill - SFS	1,164	235	10,000	235
38	Deerfield ISO - SIS	828	235		
39	Kidder Hill Wind - SIS	3,990	235		
40	Hoosic River Hydro - SFS	2,790	235	10,000	235

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 06/30/2016	Year/Period of Report End of 2016/Q2

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	Lamoille River - SIS & SFS	1,665	235		
23	Wilder Solar - SIS	312	235	25,000	235
24	Hidden Meadow Solar - SIS	1,040	235		
25	Elizabeth Copper Mine - SIS	18,000	235		
26	Elizabeth Copper Mine - SFS	3,524	235		
27	TDI Clean Energy - SIS	10,220	235		
28	Grand Isle 400 - SIS	12,076	235		
29	Otter Creek Solar I - SFS	2,498	235		
30	Otter Creek Solar II- SFS	856	235		
31	Slang Creek - SIS	27,682	235		
32	Ampersand Gilman Solar - SIS	17,508	235		
33	Ampersand Gilman Solar - SFS	1,645	235	10,000	235
34	Swanton ISO - SIS	2,557	235		
35	Ryegate & Wells River - SIS	3,051	235	26,625	235
36	Nat Grid 74GI Ski Bowl - SIS			5,000	235
37	SBVT Landfill - SFS	1,164	235	10,000	235
38	Deerfield ISO - SIS	828	235		
39	Kidder Hill Wind - SIS	3,990	235		
40	Hoosic River Hydro - SFS	2,790	235	10,000	235

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OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter /Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Asset Retirement	324,998		108/407	7,738	317,260
2	Future revenue due to income taxes	108,908		282	5,056	103,852
3	Current revenue due to income taxes	23,804		282	1,791	22,013
4	2013 NTA Study - 2 yrs	47,259		407	23,630	23,629
5	VMPD Value Sharing - 3 yrs	349,496		407	34,950	314,546
6	Depreciation Study - 4 yrs	54,370		407	5,932	48,438
7	Deerfield Wind - 3 yrs	746,597		407	74,660	671,937
8						
9						
10						
11						
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44	**TOTAL :**	1,655,432	0		153,757	1,501,675

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Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Future Revenue Due to Income Taxes	572,506	190		14,479	586,985
2	Current Revenue Due to Income Taxes	57,042		8,949		48,093
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4						
5						
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41	TOTAL	629,548		8,949	14,479	635,078

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	125,985,507	
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	106,944,823	
5	Large (or Ind.) (See Instr. 4)	57,231,869	
6	(444) Public Street and Highway Lighting	1,284,392	
7	(445) Other Sales to Public Authorities	213	
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	291,446,804	
11	(447) Sales for Resale	6,419,543	
12	TOTAL Sales of Electricity	297,866,347	
13	(Less) (449.1) Provision for Rate Refunds	-2,405,791	
14	TOTAL Revenues Net of Prov. for Refunds	300,272,138	
15	Other Operating Revenues		
16	(450) Forfeited Discounts	492,476	
17	(451) Miscellaneous Service Revenues	685,413	
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	2,288,686	
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	11,458,191	
22	(456.1) Revenues from Transmission of Electricity of Others	7,373,212	
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	22,297,978	
27	TOTAL Electric Operating Revenues	322,570,116	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
744,548				2
				3
750,711				4
585,153				5
2,440				6
14				7
				8
				9
2,082,866				10
295,646				11
2,378,512				12
				13
2,378,512				14

Line 12, column (b) includes $ -2,622,425 of unbilled revenues.

Line 12, column (d) includes -17,940 MWH relating to unbilled revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
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45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

ELECTRIC PRODUCTION, OTHER POWER SUPPLY EXPENSES, TRANSMISSION AND DISTRIBUTION EXPENSES

Report Electric production, other power supply expenses, transmission, regional control and market operation, and distribution expenses through the reporting period.

Line No.	Account (a)	Year to Date Quarter (b)
1	1. POWER PRODUCTION AND OTHER SUPPLY EXPENSES	
2	Steam Power Generation - Operation (500-509)	4,306,240
3	Steam Power Generation - Maintenance (510-515)	382,229
4	Total Power Production Expenses - Steam Power	4,688,469
5	Nuclear Power Generation - Operation (517-525)	2,053,887
6	Nuclear Power Generation – Maintenance (528-532)	513,165
7	Total Power Production Expenses - Nuclear Power	2,567,052
8	Hydraulic Power Generation - Operation (535-540.1)	710,548
9	Hydraulic Power Generation – Maintenance (541-545.1)	1,052,067
10	Total Power Production Expenses – Hydraulic Power	1,762,615
11	Other Power Generation - Operation (546-550.1)	1,331,747
12	Other Power Generation - Maintenance (551-554.1)	1,776,671
13	Total Power Production Expenses - Other Power	3,108,418
14	Other Power Supply Expenses	
15	Purchased Power (555)	138,603,591
16	System Control and Load Dispatching (556)	475,106
17	Other Expenses (557)	51,530
18	Total Other Power Supply Expenses (line 15-17)	139,130,227
19	Total Power Production Expenses (Total of lines 4, 7, 10, 13 and 18)	151,256,781
20	2. TRANSMISSION EXPENSES	
21	Transmission Operation Expenses	
22	(560) Operation Supervision and Engineering	33,960
23		
24	(561.1) Load Dispatch-Reliability	90,597
25	(561.2) Load Dispatch-Monitor and Operate Transmission System	
26	(561.3) Load Dispatch-Transmission Service and Scheduling	
27	(561.4) Scheduling, System Control and Dispatch Services	1,641,960
28	(561.5) Reliability, Planning and Standards Development	
29	(561.6) Transmission Service Studies	
30	(561.7) Generation Interconnection Studies	
31	(561.8) Reliability, Planning and Standards Development Services	279,620
32	(562) Station Expenses	317,666
33	(563) Overhead Line Expenses	116,375
34	(564) Underground Line Expenses	
35	(565) Transmission of Electricity by Others	45,619,707
36	(566) Miscellaneous Transmission Expenses	
37	(567) Rents	142,308
38	(567.1) Operation Supplies and Expenses (Non-Major)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC PRODUCTION, OTHER POWER SUPPLY EXPENSES, TRANSMISSION AND DISTRIBUTION EXPENSES

Report Electric production, other power supply expenses, transmission, regional control and market operation, and distribution expenses through the reporting period.

Line No.	Account (a)	Year to Date Quarter (b)
39	TOTAL Transmission Operation Expenses (Lines 22 - 38)	48,242,193
40	Transmission Maintenance Expenses	
41	(568) Maintenance Supervision and Engineering	3,403
42	(569) Maintenance of Structures	
43	(569.1) Maintenance of Computer Hardware	
44	(569.2) Maintenance of Computer Software	
45	(569.3) Maintenance of Communication Equipment	19,947
46	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	
47	(570) Maintenance of Station Equipment	316,152
48	(571) Maintenance Overhead Lines	1,513,793
49	(572) Maintenance of Underground Lines	
50	(573) Maintenance of Miscellaneous Transmission Plant	
51	(574) Maintenance of Transmission Plant	
52	TOTAL Transmission Maintenance Expenses (Lines 41 - 51)	1,853,295
53	Total Transmission Expenses (Lines 39 and 52)	50,095,488
54	3. REGIONAL MARKET EXPENSES	
55	Regional Market Operation Expenses	
56	(575.1) Operation Supervision	
57	(575.2) Day-Ahead and Real-Time Market Facilitation	
58	(575.3) Transmission Rights Market Facilitation	
59	(575.4) Capacity Market Facilitation	
60	(575.5) Ancillary Services Market Facilitation	
61	(575.6) Market Monitoring and Compliance	
62	(575.7) Market Facilitation, Monitoring and Compliance Services	1,299,177
63	Regional Market Operation Expenses (Lines 55 - 62)	1,299,177
64	Regional Market Maintenance Expenses	
65	(576.1) Maintenance of Structures and Improvements	
66	(576.2) Maintenance of Computer Hardware	
67	(576.3) Maintenance of Computer Software	
68	(576.4) Maintenance of Communication Equipment	
69	(576.5) Maintenance of Miscellaneous Market Operation Plant	
70	Regional Market Maintenance Expenses (Lines 65-69)	
71	TOTAL Regional Control and Market Operation Expenses (Lines 63,70)	1,299,177
72	4. DISTRIBUTION EXPENSES	
73	Distribution Operation Expenses (580-589)	2,825,981
74	Distribution Maintenance Expenses (590-598)	12,502,948
75	Total Distribution Expenses (Lines 73 and 74)	15,328,929

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ELECTRIC CUSTOMER ACCOUNTS, SERVICE, SALES, ADMINISTRATIVE AND GENERAL EXPENSES

Report the amount of expenses for customer accounts, service, sales, and administrative and general expenses year to date.

Line No.	Account (a)	Year to Date Quarter (b)
1	(901-905) Customer Accounts Expenses	4,029,387
2	(907-910) Customer Service and Information Expenses	1,237,398
3	(911-917) Sales Expenses	33,671
4	8. ADMINISTRATIVE AND GENERAL EXPENSES	
5	Operations	
6	920 Administrative and General Salaries	6,139,882
7	921 Office Supplies and Expenses	2,320,355
8	(Less) 922 Administrative Expenses Transferred-Credit	3,135,019
9	923 Outside Services Employed	2,097,199
10	924 Property Insurance	884,859
11	925 Injuries and Damages	1,665,911
12	926 Employee Pensions and Benefits	7,585,698
13	927 Franchise Requirements	
14	928 Regulatory Commission Expenses	73,468
15	(Less) 929 Duplicate Charges-Credit	147,805
16	930.1General Advertising Expenses	56,325
17	930.2Miscellaneous General Expenses	289,993
18	931 Rents	158,310
19	TOTAL Operation (Total of lines 6 thru 18)	17,989,176
20	Maintenance	
21	935 Maintenance of General Plant	3,659,591
22	TOTAL Administrative and General Expenses (Total of lines 19 and 21)	21,648,767

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Village of Ludlow	Various	Village of Ludlow	FNO
2	Village of Hyde Park	Various	Village of Hyde Park	FNO
3	Vermont Electric Coop	VELCO	Vermont Electric Coop	FNO
4	Woodsville Fire District	Various	Woodsville Fire District	FNO
5	New Hampshire Electric Cooperative	Various	New Hampshire Electric Coop	FNO
6	Public Service Company of New Hampshire	Various	Public Service Co of New Hampshie	FNO
7	Washington Electric	VELCO	Washington Electric	FNO
8	Village of Northfield	VELCO	Village of Northfield	FNO
9	Village of Jacksonville	VELCO	Village of Jacksonville	FNO
10	Village of Hardwick	VELCO	Village of Hardwick	FNO
11	Burlington Electric	GMP	Burlington Electric	FNO
12	MAG Energy Solutions	Hydro Quebec Transgererie	ISO New England	NF
13	Cargill	Hydro Quebec Transgererie	ISO New England	FNO
14	Nalcor	Hydro Quebec Transgererie	ISO New England	FNO
15	Nalcor	Hydro Quebec Transgererie	ISO New England	NF
16	Hydro Quebec	Hydro Quebec Transgererie	ISO New England	FNO
17	Hydro Quebec	Hydro Quebec Transgererie	ISO New England	NF
18	Burlington Electric	GMP	Burlington Electric	NF
19	Brookfield Energy Marketing	Hydro Quebec Transgererie	ISO New England	NF
20	Ontario Power Generation	Hydro Quebec Transgererie	ISO New England	FNO
21	Ontario Power Generation	Hydro Quebec Transgererie	ISO New England	NF
22	Ontario Power Generation Energy Trad	Hydro Quebec Transgererie	ISO New England	FNO
23	Canadian Wood Products	Hydro Quebec Transgererie	ISO New England	NF
24	Royal Bank of Canada	Hydro Quebec Transgererie	ISO New England	FNO
25	Royal Bank of Canada	Hydro Quebec Transgererie	ISO New England	NF
26	VELCO Highgate Transmission Facility			
27	Hydro Quebec	Hydro Quebec Transgererie	ISO New England	NF
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
3	Various	Various		28,003	27,163	1
3	Various	Hyde Park		6,386	6,194	2
3	Various	Various		60,264	58,244	3
3	Various	Woodsville		12,125	11,761	4
3	Various	Various		9,667	9,061	5
3	Various	Various		82,864	80,967	6
3	VELCO	Washington Electric		31,790	27,833	7
3	VELCO	Northfield		15,144	14,690	8
3	VELCO	Jacksonville		3,046	2,891	9
3	VELCO	Hardwick		15,696	15,225	10
3	VELCO	Burlington Electric		2,733	2,591	11
3	Various	Various		703	703	12
3	Various	Various		30,569	30,569	13
3	Various	Various		30,569	30,569	14
3	Various	Various		58	58	15
3	New England Border	Sandy Pond, MA		30,569	30,569	16
3	New England Border	Sandy Pond, MA		3,926	3,926	17
3	Georgia	Burlington Electric		16,015	16,015	18
3	Burlington Electric	Various		319,375	319,375	19
3	New England Border	Sandy Pond, MA		26,202	26,202	20
3	New England Border	Sandy Pond, MA		7,440	7,440	21
3	New England Border	Sandy Pond, MA		26,202	26,202	22
3	New England Border	Sandy Pond, MA		20	20	23
3	New England Border	Sandy Pond, MA		26,202	26,202	24
3	New England Border	Sandy Pond, MA		10,136	10,136	25
	Georgia, VT	Burlington, VT				26
3	New England Border	Sandy Pond, MA		30,569	30,569	27
						28
						29
						30
						31
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						34
			0	**826,273**	**815,175**	

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS				
Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
128,050		15,541	143,591	1
32,705		3,780	36,485	2
297,600		51,970	349,570	3
55,679		13,582	69,261	4
53,005		14,751	67,756	5
418,326		107,188	525,514	6
180,952		-14,676	166,276	7
73,585		-1,623	71,962	8
13,701		-1,314	12,387	9
91,509		-6,000	85,509	10
12,464		468	12,932	11
2,490		-680	1,810	12
107,972		-107,972		13
107,972		-35,990	71,982	14
102		-70	32	15
107,972		-71,981	35,991	16
22,573		-3,560	19,013	17
136,300			136,300	18
1,957,767			1,957,767	19
92,547			92,547	20
25,700		-25,394	306	21
92,547			92,547	22
148			148	23
92,547		-12,664	79,883	24
36,039			36,039	25
2,912,094			2,912,094	26
265,950			265,950	27
				28
				29
				30
				31
				32
				33
				34
7,318,296	**0**	**-74,644**	**7,243,652**	

Schedule Page: 328 Line No.: 1 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 1 Column: m

Ludlow

Regulatory Commission expense	$6,759
Delivery point charge	1,356
Load dispatch	11,815
Phase in	(4,389)
TOTAL	$15,541

Schedule Page: 328 Line No.: 2 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 2 Column: m

Hyde Park

Regulatory Commission expense	$1,504
Delivery point charge	452
Load dispatch	3,025
Phase in	203
Specific Facility Credit	(1,404)
TOTAL	$3,780

Schedule Page: 328 Line No.: 3 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 3 Column: m

Vermont Electric Cooperative

Distribution	$18,231
Regulatory Commission expense	14,153
Delivery point charge	7,232
Load dispatch	28,475
Phase in	5,677
Specific Facility Credit	(21,798)
TOTAL	$51,970

Schedule Page: 328 Line No.: 4 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 4 Column: m

Woodsville

Regulatory Commission expense	$2,848
Delivery point charge	452
Load dispatch	4,924
Phase in	3,506
Distribution	1,852
TOTAL	$13,582

Schedule Page: 328 Line No.: 5 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 5 Column: m

New Hampshire Electric Cooperative

Regulatory Commission expense	$2,298
Load dispatch	4,787
Distribution	3,403
Phase in	4,263
TOTAL	$14,751

Schedule Page: 328 Line No.: 6 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 6 Column: m

Public Service Company of New Hampshire

Regulatory Commission expense	$19,784
Delivery point charge	3,164
Load dispatch	35,826
Distribution	20,205
Phase in	28,209
TOTAL	$107,188

Schedule Page: 328 Line No.: 7 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 7 Column: m

Washington Electric

Regulatory Commission expense	$7,879
Delivery point charge	3,164
Load dispatch	16,647
Phase in	(34,650)
Specific Facility Credit	(7,716)
TOTAL	$(14,676)

Schedule Page: 328 Line No.: 8 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 8 Column: m

Village of Northfield

Regulatory Commission expense	$3,576
Delivery point charge	452
Load dispatch	6,187
Phase in	(11,838)
TOTAL	$(1,623)

Schedule Page: 328 Line No.: 9 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 9 Column: m

Village of Jacksonville

Regulatory Commission expense	$721
Delivery point charge	452
Load dispatch	1,365
Phase in	(3,852)
TOTAL	$(1,314)

Schedule Page: 328 Line No.: 10 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 10 Column: m

Village of Hardwick

Regulatory Commission expense	$3,905
Delivery point charge	904
Load dispatch	7,269
Phase in	(14,058)
Specific Facility Credit	(4,020)
TOTAL	$(6,000)

Schedule Page: 328 Line No.: 11 Column: e

ISO-NE Tariff 3, Section II OATT, Schedule 21

Schedule Page: 328 Line No.: 11 Column: m

Burlington Electric

Regulatory Commission expense	$657
Delivery point charge	904
Load dispatch	1,102
Phase in	(1,547)
Specific Facility Credit	(648)
TOTAL	$468

Schedule Page: 328 Line No.: 12 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 12 Column: m

Demand charges collected on behalf of others pursuant to a Brokering and Agency Agreement between Green Mountain Power and certain Phase I and II Interconnection Rights Holders.

Schedule Page: 328 Line No.: 13 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 13 Column: m

Demand charges collected on behalf of others pursuant to a Brokering and Agency Agreement between Green Mountain Power and certain Phase I and II Interconnection Rights Holders.

Schedule Page: 328 Line No.: 14 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 14 Column: m

Demand charges collected on behalf of others pursuant to a Brokering and Agency Agreement between Green Mountain Power and certain Phase I and II Interconnection Rights Holders.

Schedule Page: 328 Line No.: 15 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 15 Column: m

Demand charges collected on behalf of others pursuant to a Brokering and Agency Agreement between Green Mountain Power and certain Phase I and II Interconnection Rights Holders.

Schedule Page: 328 Line No.: 16 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 16 Column: m

Demand charges collected on behalf of others pursuant to a Brokering and Agency Agreement between Green Mountain Power and certain Phase I and II Interconnection Rights Holders.

Schedule Page: 328 Line No.: 17 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 17 Column: m

Demand charges collected on behalf of others pursuant to a Brokering and Agency Agreement between Green Mountain Power and certain Phase I and II Interconnection Rights Holders.

Schedule Page: 328 Line No.: 18 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 20 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 21 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 21 Column: m

Demand charges collected on behalf of others pursuant to a Brokering and Agency Agreement between Green Mountain Power and certain Phase I and II Interconnection Rights Holders.

Schedule Page: 328 Line No.: 22 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 23 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 24 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Schedule Page: 328 Line No.: 24 Column: m

Demand charges collected on behalf of others pursuant to a Brokering and Agency Agreement between Green Mountain Power and certain Phase I and II Interconnection Rights Holders.

Schedule Page: 328 Line No.: 25 Column: e

ISO-NE RTO Tariff 3, Section II OATT, Schedules 20A and 20A-GMP.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Received from Wheeler							
2	VELCO	FNS	706,617	701,177	6,843,201		46,323	6,889,524
3	NYPA	OLF			27,376			27,376
4	NATIONAL GRID	FNS			591,614		4,005	595,619
5	VELCO PHASE 1&11	LFP			713,422			713,422
6	ISO NEW ENGLAND	FNS			15,004,085			15,004,085
7	VERMONT ELEC COOP	OS			82,643			82,643
8	VERMONT ELEC PWR PROD	OS			646			646
9	CONNECTICUT LG & PWR	OS	20,192		34,693			34,693
10	FERC 890 COMPLIANCE						524	524
11								
12								
13								
14								
15								
16								
	TOTAL		726,809	701,177	23,297,680		50,852	23,348,532

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 06/30/2016	Year/Period of Report End of 2016/Q2

Depreciation, Depletion and Amortization of Electric Plant (Accts 403, 403.1, 404, and 405) (Except Amortization of Acquisition Adjustments)

1. Report the year to date amounts of depreciation expense, asset retirement cost depreciation, depletion and amortization, except amortization of acquisition adjustments for the accounts indicated and classified according to the plant functional groups described.

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Other Limited-Term Electric Plant (Account 404) (e)	Amortization of Other Electric Plant (Account 405) (e)	Total (f)
1	Intangible Plant			6,711,022		6,711,022
2	Steam Production Plant	566,416				566,416
3	Nuclear Production Plant	500,467				500,467
4	Hydraulic Production Plant Conv	2,412,723				2,412,723
5	Hydraulic Production Plant - Pumped Storage					
6	Other Production Plant	3,832,426	67,530			3,899,956
7	Transmission Plant	1,892,181				1,892,181
8	Distribution Plant	7,780,861	2,358			7,783,219
9	General Plant	2,306,667				2,306,667
10	Common Plant					
11	TOTAL ELECTRIC (lines 2 through 10)	19,291,741	69,888	6,711,022		26,072,651

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	6,147,047	9,820,761		
3	Net Sales (Account 447)	(3,231,685)	(4,653,504)		
4	Transmission Rights	(138,993)	(180,090)		
5	Ancillary Services	400,816	486,616		
6	Other Items (list separately)				
7	ICAP Settlement	5,224,822	10,075,888		
8	RT Regulations Settlement	211,145	366,308		
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
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32					
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35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	8,613,152	15,915,979		

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 06/30/2016	Year/Period of Report End of 2016/Q2

MONTHLY PEAKS AND OUTPUT

(1) (1) Report the monthly peak load and energy output. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non- integrated system. In quarter 1 report January, February, and March only. In quarter 2 report April, May, and June only. In quarter 3 report July, August, and September only.
(2) Report on column (b) by month the system's output in Megawatt hours for each month.
(3) Report on column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on columns (e) and (f) the specified information for each monthly peak load reported on column (d).
(6) Report Monthly Peak Hours in military time; 0100 for 1:00 AM, 1200 for 12 AM, and 1830 for 6:30 PM, etc.

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (MWH) (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
1	January				0	0
2	February				0	0
3	March				0	0
4	Total					
5	April	397,828	67,720	524	4	2100
6	May	371,281	28,854	538	28	2100
7	June	386,749	34,994	573	20	2100
8	Total	1,155,858	131,568	1,635		
9	July				0	0
10	August				0	0
11	September				0	0
12	Total					

Name of Respondent Green Mountain Power Corp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 06/30/2016	Year/Period of Report End of 2016/Q2

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	817	4	148	714	98	10			-5
2	February	804	14	19	697	97	10			
3	March	706	2	19	618	84	10			-6
4	Total for Quarter 1				2,029	279	30			-11
5	April	657	5	8	577	72	10			-2
6	May	662	28	21	582	71	10			-1
7	June	696	20	21	618	78	10			-10
8	Total for Quarter 2				1,777	221	30			-13
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year				3,806	500	60			-24

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Green Mountain Power Corp	(1) [X] An Original (2) [ ] A Resubmission	06/30/2016	End of 2016/Q2

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									