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
NSTAR Electric Company	End of 2018/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of _____ , we have also reviewed schedules _____of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the

termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

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.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; .....

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

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

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/Period of Report
NSTAR Electric Company	End of 2018/Q4

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)*
800 Boylston Street, Boston, Massachusetts 02199

05 Name of Contact Person	06 Title of Contact Person
Carla J. Dacey	Manager-Rev & Reg Accounting

07 Address of Contact Person *(Street, City, State, Zip Code)*
247 Station Drive, SUM NE-230, Westwood, Massachusetts 02090-9230

08 Telephone of Contact Person,*Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(781) 441-8816	(1) [X] An Original (2) [ ] A Resubmission	/ /

ANNUAL 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)*
Jay S. Buth		
02 Title	Jay S. Buth	04/12/2019
Vice President, Controller and CAO		

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
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	Not Applicable
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	Not Applicable
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	Not Applicable
25	Unrecovered Plant and Regulatory Study Costs	230	Not Applicable
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	Not Applicable
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	Not Applicable
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	Not Applicable
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	Not Applicable
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	Not Applicable
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	Not Applicable
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	Not Applicable
64	Hydroelectric Generating Plant Statistics	406-407	Not Applicable
65	Pumped Storage Generating Plant Statistics	408-409	Not Applicable
66	Generating Plant Statistics Pages	410-411	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	None
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [ ] Two copies will be submitted [X] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	*(Mo, Da, Yr)* / /	End of 2018/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Jay S. Buth, Vice President, Controller and Chief Accounting Officer
NSTAR Electric Company
107 Selden Street
Berlin, CT 06037

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Incorporated in Massachusetts in January, 1886.

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

N/A

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Delivery of electricity in the state of Massachusetts.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report *(Mo, Da, Yr)*	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Name of Controlling Organization: Eversource Energy, a Massachusetts business trust and voluntary association headquartered in Boston, Massachusetts and Hartford, Connecticut, is a public utility holding company subject to regulation by the FERC under the Public Utility Company Holding Act of 2005, which wholly and directly owns the respondent.

Manner in Which Control was Held: Ownership of Common Stock

Extent of Control: 100%

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Harbor Electric Energy Company	Electric utility	100%	
2				
3	Yankee Atomic Electric Company	Nuclear electric generation	21%	
4		(unit permanently closed)		
5				
6	Connecticut Yankee Atomic Power Company	Nuclear electric generation	23.5%	
7		(unit permanently closed)		
8				
9	Maine Yankee Atomic Power Company	Nuclear electric generation	7%	
10		(unit permanently closed)		
11				
12	New England Hydro-Transmission Elec., Co., Inc	Electric transmission		(1)
13				
14	New England Hydro-Transmission Corporation	Electric transmission		(1)
15				
16				
17				
18				
19	(1) The Company owns 14.47% of the common			
20	stock with a 7.9% voting interest.			
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27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chairman	James J. Judge	
2	Chief Executive Officer	Werner J. Schweiger	
3	President and Chief Operating Officer	Craig A. Hallstrom	
4	Executive Vice President and General Counsel	Gregory B. Butler	
5	Executive Vice President and Chief Financial Officer	Philip J. Lembo	
6	Senior Vice President-Finance and Regulatory		
7	and Treasurer	John M. Moreira	
8	Senior Vice President-Transmission	Kathleen A. Shea	
9	Vice President-Supply Chain, Environmental Affairs		
10	and Property Management	Ellen K. Angley	
11	Vice President, Controller and Chief Accounting Officer	Jay S. Buth	
12	Vice President-Energy Supply	James G. Daly	
13	Vice President-Electric Field Operations	Douglas W. Foley	
14	Vice President-Electric System Operations	Michael F. Hayhurst	
15	Vice President-Station Operations and		
16	Field Engineering/Communications	Joseph D. Luchini	
17	Vice President-Engineering	Paul R. Renaud	
18	Vice President-Rates and Regulatory Requirements		
19	and Treasurer	Christine L. Vaughan	
20	Secretary and Clerk	Richard J. Morrison	
21			
22	See Footnotes for Page 104 for changes to		
23	incumbents made during the year.		
24			
25	Salaries are not disclosed as they are paid by		
26	Eversource Energy Service Company.		
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FOOTNOTE DATA

Schedule Page: 104 Line No.: 7 Column: b

John M. Moreira was elected Senior Vice President-Finance and Regulatory and Treasurer, effective September 12, 2018.

Schedule Page: 104 Line No.: 8 Column: b

Kathleen A. Shea resigned as Senior Vice President-Transmission, effective May 4, 2018.

Schedule Page: 104 Line No.: 16 Column: b

Joseph D. Luchini, formerly Vice President-Station Operations and Field Engineering/Communications, passed away unexpectedly on July 3, 2018.

Schedule Page: 104 Line No.: 17 Column: b

Paul R. Renaud resigned as Vice President-Engineering, effective April 9, 2018.

Schedule Page: 104 Line No.: 19 Column: b

Christine M. Vaughan, formerly Vice President-Rates and Regulatory Requirements and Treasurer, resigned effective July 27, 2018.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Gregory B. Butler	56 Prospect Street, Hartford, CT 06103
2	(Executive Vice President and General Counsel)	
3		
4	James J. Judge (Chairman)	800 Boylston Street, Boston, MA 02199
5		
6	Philip J. Lembo	800 Boylston Street, Boston, MA 02199
7	(Executive Vice President and Chief Financial Officer)	
8		
9	Werner J. Schweiger (Chief Executive Officer)	107 Selden Street, Berlin, CT 06037
10		
11	The Company does not have an Executive Committee.	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	[X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	ISO New England Inc. Transmission, Markets and	ER07-549, EL07-71, ER19-123
2	Services Tariff, Section II, Schedule 21-NSTAR	
3		
4	ISO New England Inc. Transmission, Markets and	ER05-754, ER18-132
5	Services Tariff, Section II, Schedule 20A-NSTAR	
6		
7	ISO-NE Transmission, Markets and Services Tariff,	RT04-2, ER04-116, ER05-374, ER18-1722
8	Section II, Attachment F	
9		
10	NSTAR Electric Company, Rate Schedule FERC No. 210	ER07-548, ER19-431
11	(MATEP LLC - Brighton Station #329)	
12		
13	NSTAR Electric Company, Rate Schedule FERC No. 220	ER12-956
14	(MATEP LLC - Colburn Station #350)	
15		
16	NSTAR Electric Company, Rate Schedule FERC No. 205	ER10-568
17	(Massachusetts Port Authority)	
18		
19	NSTAR Electric Company (f/k/a Boston Edison	ER07-595
20	Company), Rate Schedule FERC No. 200	
21	(Massachusetts Bay Transportation Authority)	
22		
23	Space Reserved for Future Contract	
24		
25		
26	NSTAR Electric Company (f/k/a Boston Edison	ER91-149, ER86-562, ER87-232
27	Company), Rate Schedule FERC No. 169	
28	(Concord Municipal Light Plant)	
29		
30	NSTAR Electric Company (f/k/a Boston Edison	ER99-2598
31	Company), Rate Schedule FERC No. 196 (ANP	
32	Blackstone Energy Company - Annual	
33	Facilities Charge)	
34		
35	NSTAR Electric Company (f/k/a Commonwealth	ER03-1348
36	Electric Company), Service Agreement No. 27	
37	under ISO New England Inc. Transmission,	
38	Markets and Services Tariff, Section II, Schedule	
39	21-NSTAR (Entergy Nuclear Generation Company	
40	RFA Barnstable Capacitor Bank)	
41		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INFORMATION ON FORMULA RATES (continued)

FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	[X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	ISO New England Inc. Transmission, Markets and	ref. ER01-523
2	Services Tariff, Section II, Schedule 22 -	
3	LGIA, Original Service Agreement No.	
4	LGIA-ISONE/ NSTAR-15-01	
5	(Calpine Fore River Energy Center, LLC -	
6	Annual Facilities Charge)	
7		
8	NSTAR Electric Company (f/k/a Boston Edison	ER01-3138
9	Company), Service Agreement No. 73 under ISO	
10	New England Inc. Transmission, Markets and	
11	Services Tariff, Section II, Schedule 21-NSTAR	
12	(Granite Ridge (AES Londonderry) - Annual	
13	Facilities Charge)	
14		
15	NSTAR Electric Company (f/k/a Boston Edison	ER98-4332
16	Company), Rate Schedule FERC No. 193	
17	(Millennium Power Partners, L.P. - Annual	
18	Facilities Charge)	
19		
20	ISO New England Inc. Transmission, Markets and	ref. ER02-167
21	Services Tariff, Section II, Schedule 22 - LGIA,	
22	Original Service Agreement No.	
23	LGIA-ISONE/ NSTAR-12-01	
24	(Kendall Green Energy LLC -	
25	Annual Facilities Charge)	
26		
27	NSTAR Electric Company (f/k/a Boston Edison	ER06-145
28	Company), Service Agreement No. 30 under ISO	
29	New England Inc. Transmission, Markets and	
30	Services Tariff, Section II, Schedule 21-NSTAR	
31	(New England Power (Nantucket - Merchant's	
32	Way IA) - Annual Facilities Charge)	
33		
34	NSTAR Electric Company (f/k/a Boston Edison	ER06-423
35	Company), Service Agreement No. 85 under ISO	
36	New England Inc. Transmission, Markets and	
37	Services Tariff, Section II, Schedule 21-NSTAR	
38	(New England Power - Dewar Street IA)	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INFORMATION ON FORMULA RATES (continued)
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	[X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	NSTAR Electric Company (f/k/a Boston Edison	ER89-612
2	Company), Rate Schedule FERC No. 152 (BECO	
3	HQ AC Support Agreement)	
4		
5	NSTAR Electric Company (f/k/a Boston Edison	Filed 3/31/1980
6	Company), Rate Schedule FPC No. [ ] (New	
7	England Power - Lines 255-2337 and 255-2338)	
8		
9	ISO New England Inc. Transmission, Markets and	ER14-2596
10	Services Tariff, Section II, Schedule 21-NSTAR,	
11	Original Service Agreement No. TSA-NSTAR-001	
12	(MBTA LSA - Direct Assignment Charge)	
13		
14	NSTAR Electric Company	ER18-1574
15	Service Agreement No. RFA-NSTAR-002	
16	(NSTAR - Milford Power, LLC -	
17	Annual Facilities Charge)	
18		
19		
20	NSTAR Electric Company	ER16-2189
21	Rate Schedule FERC No. 263	
22	(NSTAR - HQUS Transfer Agreement)	
23		
24	NSTAR Electric Company	ER15-1383
25	Rate Schedule FERC No. 280	
26	(NSTAR - HQUS Transfer Agreement -	
27	CMEEC Use Rights)	
28		
29	NSTAR Electric Company	ER17-235
30	Service Agreement No. FSA-NSTAR-001	
31	(National Grid Facilities Support	
32	Agreement for Edgar-Field Street)	
33		
34	NSTAR Electric Company	ER18-1170
35	Rate Schedule FERC No. TSA-NSTAR-009	
36	(NSTAR – Nalcor Energy Marketing Corporation	
37	Transfer Agreement - CMEEC Use Rights)	
38		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INFORMATION ON FORMULA RATES (continued)

FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	[X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	ISO-NE Transmission, Markets and Services Tariff,	RT04-2, ER04-116, ER18-132
2	Section II, Schedule 1, Appendix A	
3		
4	Space Reserved for Future Contract	
5		
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9	ISO-NE Transmission, Markets and Services Tariff,	ER03-1247, ER05-1117, ER19-122, ER19-123
10	Section II, Schedule 21-ES	
11		
12	ISO-NE Transmission, Markets and Services Tariff,	ER05-754, ER18-132
13	Section II, Schedule 20A-ES	
14		
15	NSTAR Electric Company	ER05-967, ER18-749
16	Service Agreement No. IA-NU-02	
17	(Essential Power Massachusetts, LLC)	
18		
19	NSTAR Electric Company (f/k/a Western	ER96-858
20	Massachusetts Electric Company) Rate Schedule	
21	FERC No. 405 (New England Power Company)	
22		
23	NSTAR Electric Company, Rate Schedule	ER18-749
24	FERC No. 407 (Massachusetts Municipal Wholesale	
25	Electric Company – Stony Brook – Ludlow Agreement)	
26		
27	NSTAR Electric Company,	ER17-1335, ER18-749
28	Service Agreement No. IA-ES-38,	
29	(Nautilus Hydro, LLC - Dwight Hydro Generator IA)	
30		
31	NSTAR Electric Company,	ER17-1336, ER18-749
32	Service Agreement No. IA-ES-39,	
33	(Nautilus Hydro, LLC - Gardner Fall Generator IA)	
34		
35	NSTAR Electric Company,	ER17-1338, ER18-749
36	Service Agreement No. IA-ES-40,	
37	(Nautilus Hydro, LLC - Indian Orchard Generator I)	
38		
39	NSTAR Electric Company,	ER17-1339, ER18-749
40	Service Agreement No. IA-ES-41,	
41	(Nautilus Hydro, LLC - Putts Bridge Generator IA)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INFORMATION ON FORMULA RATES (continued)

FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	[X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	NSTAR Electric Company,	ER17-1340, ER18-749
2	Service Agreement No. IA-ES-42,	
3	(Nautilus Hydro, LLC - Red Bridge Generator IA)	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	[X] Yes [ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20170728-5230	07/28/2017	RT04-2-000	Annual New England Participating	ISO New England Inc. Transmission
2		07/28/2017	ER09-1532-000	Transmission Owners Administrative	Markets and Services Tariff
3				Regional Network Service	Attachment F
4				Information Filing	
5					
6	20180531-5427	05/31/2018	ER09-1243-000	Annual Informational Filing	ISO New England Inc. Transmission
7		05/31/2018	ER07-549-000	of NSTAR Electric Company	Markets and Services Tariff, Section II,
8					Schedule 21-NSTAR
9					
10	20180629-5315	06/29/2018	ER09-1243-000	Annual Informational Filing	ISO New England Inc. Transmission
11	20180629-5316	06/29/2018	ER07-549-000	CWIP Supplement of NSTAR	Markets and Services Tariff, Section II,
12				Electric Company	Schedule 21-NSTAR
13					
14	20180731-5221	07/31/2018	RT04-2-000	Annual New England Participating	ISO New England Inc. Transmission
15		07/31/2018	ER09-1532-000	Transmission Owners Administrative	Markets and Services Tariff
16				Regional Network Service	Attachment F
17				Information Filing	
18					
19	20180917-5054	09/17/2018	RT04-2-000	Supplement to July 31, 2018	ISO New England Inc. Transmission
20		09/17/2018	ER09-1532-000	Annual New England Participating	Markets and Services Tariff
21				Transmission Owners Administrative	Attachment F
22				Regional Network Service	
23				Information Filing	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1	110-111	Comp Balance Sheet (Assets and Other Debt)	c	3
2	112-113	Comp Balance Sheet (Liabilities and Other Credits)	c,d	2,3,16,18,21
3	200-201	Summary of Utility Plant & Accumulated Provisions	c	21
4	204-207	Electric Plant In Service (Acct 101 - 103 and 106)	g	5,100
5	204-207	Electric Plant In Service (Acct 101 - 103 and 106)	b,g	9,13,49,50,58,61,62,66
6				67,75,99,104
7	219	Accum Provision for Depr of Electric (Account 108)	b	19,25,26,28
8	234	Accumulated Deferred Income Taxes	b,c	18
9	234	Accumulated Deferred Income Taxes	c	2
10	262-263	Taxes Accrued, Prepaid and Charged During Year	i	29,32
11	275	Accum Deferred Income Taxes-Property (Acct. 282)	k	9
12	277	Accuum Deferred Income Taxes-Other (Acct 283)	k	19
13	278	Other Regulatory Liabilities (Account 254)	f	3
14	300	Electric Operating Revenues (Account 400)	b	21,22
15	320-323	Electric Operation and Maintenance Expenses	b	112
16	320-323	Electric Operation and Maintenance Expenses	b,c	98,198
17	336	Deprec. & Amort. Of electric Plant (403, 404, 405)	b	7,8,10
18	400	Monthly Transmission System Peak Load	b	1-17
19	401b	Monthly Peaks and Output	d	29-40
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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. None

2. None

3. None

4. None

5. None

6. During 2018, the Company did not assume any obligations as a guarantor of another's performance.

   The amount of short-term borrowings that may be incurred by NSTAR Electric is subject to periodic approval by the FERC. On November 30, 2017, the FERC granted authorization to allow NSTAR Electric to issue total short-term debt securities in an aggregate principal amount not to exceed $655 million outstanding at any one-time, effective December 31, 2017 through December 30, 2019.

   NSTAR Electric is a party to a five-year $650 million revolving credit facility. The revolving credit facility's termination date is December 8, 2023. The revolving credit facility serves to backstop NSTAR Electric's $650 million commercial paper program. As of December 31, 2018, NSTAR Electric had no borrowings outstanding under this facility.

   As of December 31, 2018, NSTAR Electric had approximately $278.5 million in borrowings outstanding under its commercial paper program.

7. None

8. Estimated Annual Effect and Nature of Important Wage Scale Changes

Company	Group	Effective Date	2018 Number of Employees	General Wage Increase Percent	Estimated Annualized Cost of Increase
NSTAR	USWA 12004	03/31/18	254	2.75%	$ 679,600
NSTAR	UWUA 369	06/01/18	1,692	3.00%	$ 4,678,857
Western Mass Electric	IBEW (Physical and Technical)	10/01/18	221	3.00%	$ 539,134

9. For a discussion of materially important legal proceedings, see Page 123, Notes to Financial Statements, Note 12, Commitments and Contingencies.

10. None

11. (Reserved)

12. N/A

13. Changes in the officers and directors of the respondent during the period have been reported on pages 104 and 105 and the corresponding footnotes thereto.

There were no changes in the major security holders and voting powers during the period.

14. NSTAR Electric Company proprietary capital ratio is greater than 30%.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	*(Mo, Da, Yr)* / /	End of 2018/Q4

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	10,932,014,320	10,301,966,288
3	Construction Work in Progress (107)	200-201	470,314,379	447,851,109
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		11,402,328,699	10,749,817,397
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,967,931,831	2,802,914,195
6	Net Utility Plant (Enter Total of line 4 less 5)		8,434,396,868	7,946,903,202
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)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		8,434,396,868	7,946,903,202
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		4,858,250	5,030,847
19	(Less) Accum. Prov. for Depr. and Amort. (122)		94,887	92,740
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	16,024,653	6,791,505
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)		901,590	1,008,883
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		132,809,645	126,948,028
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)		154,499,251	139,686,523
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		0	0
36	Special Deposits (132-134)		13,054,421	12,917,853
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		299,302,350	279,632,436
41	Other Accounts Receivable (143)		134,848,169	125,933,178
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		74,411,265	69,561,390
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		32,582,097	41,403,616
45	Fuel Stock (151)	227	0	0
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	61,693,671	49,531,530
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	65,594,115	50,391,921

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	*(Mo, Da, Yr)* / /	End of 2018/Q4

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	45,571	391,487
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)		41,020,772	11,963,323
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		107,588	73,730
60	Rents Receivable (172)		1,449,638	5,195,312
61	Accrued Utility Revenues (173)		34,517,648	49,864,790
62	Miscellaneous Current and Accrued Assets (174)		0	0
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)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		609,804,775	557,737,786
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		17,645,331	19,455,830
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	1,428,335,359	1,504,849,772
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,267,208	373,635
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)		303	-92,034
77	Temporary Facilities (185)		-522,765	-1,270,673
78	Miscellaneous Deferred Debits (186)	233	90,022,171	76,809,391
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)		10,638,072	11,319,222
82	Accumulated Deferred Income Taxes (190)	234	462,181,372	398,218,961
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,010,567,051	2,009,664,104
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		11,209,267,945	10,653,991,615

Schedule Page: 110 Line No.: 2 Column: c

In the third quarter of 2018, management identified and corrected a $1.1 million error related to retirements that resulted in a misclassification as of December 31, 2017 between accounts 101 and 108.

Schedule Page: 110 Line No.: 3 Column: c

WEST:
Information on Formula Rates:
Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Schedule Page: 110 Line No.: 52 Column: c

Represents the value of Renewable Energy Certificates (RECs) that NSTAR Electric Company uses to meet the Commonwealth of Massachusetts' Renewable Portfolio Standards requirements. These RECs are recorded in Account 158.3.

Schedule Page: 110 Line No.: 52 Column: d

Represents the value of Renewable Energy Certificates (RECs) that NSTAR Electric Company uses to meet the Commonwealth of Massachusetts' Renewable Portfolio Standards requirements. These RECs are recorded in Account 158.3.

Schedule Page: 110 Line No.: 57 Column: c

At December 31, 2018, the total Prepayments balance in Account 165 includes NSTAR Electric East related prepayments of the following amounts:

Prepaid State Taxes	$ 6,309,081	dr.
Prepaid Insurance	1,824,792	dr.
Prepaid Interest	89,097	dr.
Prepaid Lease	80,133	dr.
Prepaid Workers Comp.	638,600	dr.
Prepaid Agency Fees	518,788	dr.
Prepaid Postage	33,600	dr.
Prepaid Federal Taxes	26,592,632	dr.
Prepaid Other	28,628	dr.
	$ 36,115,352	dr.

At December 31, 2018, the total Prepayments balance in Account 165 includes NSTAR Electric West related prepayments of the following amounts:

Prepaid State Taxes	1,415,621	dr.
Prepaid Insurance	374,546	dr.
Prepaid Lease	70,874	dr.
Prepaid Workers Comp.	212,060	dr.
Prepaid Software License Maint.	62,220	dr.
Prepaid Vehicle Property Taxes	45,256	dr.
Prepaid Vehicle Costs	92,736	dr.
Prepaid Federal Taxes	2,625,382	dr.
Prepaid Other	6,725	dr.
	$ 4,905,420	dr.

At December 31, 2018, the total Prepayments balance in Account 165 includes NSTAR Electric West transmission related prepayments of the following amounts:

Prepaid State Taxes	$	1,524,190	dr.
Prepaid Federal Taxes		(7,932,969)	cr.
Prepaid Insurance		157,140	dr.
Prepaid Lease		(500)	cr.
Prepaid Software License Maint.		15,555	dr.
Prepaid Other		5,516	dr.
Total	$	(6,231,068)	cr.

Schedule Page: 110 Line No.: 69 Column: c

At December 31, 2018, the total Unamortized Debt Expenses balance in Account 181 includes NSTAR Electric East related Debt of the following amounts:

Debentures Due 03/2044	$	2,571,563	dr.
Debentures Due 03/2036		1,252,508	dr.
Debentures Due 03/2040		2,214,080	dr.
Debentures Due 10/2022		1,208,859	dr.
Debentures Due 11/2025		1,467,011	dr.
Debentures Due 06/2026		1,581,921	dr.
Debentures Due 05/2027		5,421,260	dr.
DPU Financing Plan		120,600	dr.
Total	$	15,837,802	dr.

At December 31, 2018, the total Unamortized Debt Expenses balance in Account 181 includes NSTAR Electric West related Debt of the following amounts:

Series E. Due 03/2020	$	115,801	dr.
Series G. Due 11/2023		220,279	dr.
Series H. Due 06/2026		230,720	dr.
Series F. Due 09/2021		642,725	dr.
Series D. Due 08/2037		311,081	dr.
Series B. Due 09/2034		286,923	dr.
	$	1,807,529	dr.

Schedule Page: 110 Line No.: 72 Column: c

For Form 1 reporting purposes, the following reclassification of debit or credit balance accounts at December 31, 2018 are being included with Account 182.3 - Other Regulatory Assets. The balances are as follows:

Balance in Account 182.3	1,221,308,267	dr.
Reclass of balances to Account 254: Mitigation Incentive Timing - DPU 05-89	314,352	dr.
Reclass of balances to Account 254: Pension and PBOP	33,542,425	dr.
Reclass of balances from Account 254: Basic Service Adder True up	124,429	cr.

Reclass of balances from Account 254: Deferred Transition Rev BECO	639,186	cr.
Reclass of balances to Account 254: Deferred Basic Service	4,518,390	dr.
Reclass of balances to Account 254: Deferred Transmission Revenues	88,984,023	dr.
Reclass of balances from Account 254: Deferred NSTAR Green	128,418	cr.
Reclass of balances to Account 254: Reg Asset Revenue Decoupling	717,159	dr.
Reclass of balances to Account 254: Deferred DSM Revenue	66,942,442	dr.
Reclass of balances to Account 254: Deferred Metering Costs	12,735,130	dr.
Reclass of balances to Account 254: Uncollectibles Assoc with Basic Service	181,536	dr.
Reclass of balances from Account 254: Protective Hardship Credit	16,332	cr.
Account 182.3 Being Reported	1,428,335,359	dr.

Schedule Page: 110 Line No.: 72 Column: d

For Form 1 reporting purposes, the following reclassification of debit or credit balance accounts at December 31, 2017 are being included with Account 182.3 - Other Regulatory Assets. The balances are as follows:

Balance in Account 182.3	$	1,309,814,848	dr.
Reclass of balances from Account 254: Deferred Energy Efficiency		134,250,783	dr.
Reclass of balances to Account 254: Transition Reconciliation		5,730,439	dr.
Reclass of balances from Account 254: Basic Service Uncollectibles		21,513	cr.
Reclass of balances to Account 254: Deferred Transmission Revenues		14,941,252	dr.
Reclass of balances to Account 254: Pension and PBOP		40,133,963	dr.
Account 182.3 Being Reported	$	1,504,849,772	dr.

Schedule Page: 110 Line No.: 81 Column: c

Ferc Account	Company	Ending Balance
189	East Distribution	10,439,401
	West Distribution	66,224
	West Transmission	132,447
189 Total		**10,638,072**

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2018/Q4

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	200	200
3	Preferred Stock Issued (204)	250-251	43,000,000	43,000,000
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		3,905,151	3,905,151
7	Other Paid-In Capital (208-211)	253	2,814,604,083	2,684,104,083
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	924,875,880	767,478,875
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-11,851,691	-7,584,838
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)	-1,378,596	-1,824,103
16	Total Proprietary Capital (lines 2 through 15)		3,773,155,027	3,489,079,368
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
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	2,965,000,000	2,965,000,000
22	Unamortized Premium on Long-Term Debt (225)		6,432,505	7,934,344
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		8,941,217	9,719,241
24	Total Long-Term Debt (lines 18 through 23)		2,962,491,288	2,963,215,103
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		3,442,730	3,754,457
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		45,644,076	37,562,761
29	Accumulated Provision for Pensions and Benefits (228.3)		19,113,908	94,156,648
30	Accumulated Miscellaneous Operating Provisions (228.4)		7,247,160	2,701,959
31	Accumulated Provision for Rate Refunds (229)		2,977,239	2,977,239
32	Long-Term Portion of Derivative Instrument Liabilities		0	176,612
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		63,400,062	44,574,835
35	Total Other Noncurrent Liabilities (lines 26 through 34)		141,825,175	185,904,511
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		278,500,000	234,000,000
38	Accounts Payable (232)		369,724,650	329,786,653
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		85,933,152	91,791,910
41	Customer Deposits (235)		8,002,577	8,195,387
42	Taxes Accrued (236)	262-263	5,889,025	12,127,449
43	Interest Accrued (237)		25,526,493	25,515,271
44	Dividends Declared (238)		489,998	489,998
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
NSTAR Electric Company	(1) [x] An Original (2) [ ] A Resubmission	*(mo, da, yr)* / /	end of 2018/Q4

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)		3,892,582	3,875,632
48	Miscellaneous Current and Accrued Liabilities (242)		278,161,382	228,387,970
49	Obligations Under Capital Leases-Current (243)		310,693	319,752
50	Derivative Instrument Liabilities (244)		123,106	1,232,421
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	176,611
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,056,553,658	935,545,832
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		47,196,139	52,386,151
57	Accumulated Deferred Investment Tax Credits (255)	266-267	31,935,098	10,671,434
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	52,778,123	42,391,952
60	Other Regulatory Liabilities (254)	278	1,374,279,273	1,296,363,587
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)		1,261,473,709	1,191,923,425
64	Accum. Deferred Income Taxes-Other (283)		507,580,455	486,510,252
65	Total Deferred Credits (lines 56 through 64)		3,275,242,797	3,080,246,801
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		11,209,267,945	10,653,991,615

Schedule Page: 112 Line No.: 2 Column: c

Information on Formula Rates:

EAST:

Page 106.2 line 1 Amount stipulated per contract.

Schedule Page: 112 Line No.: 2 Column: d

Information on Formula Rates:

EAST:

Page 106.2 line 1 Amount stipulated per contract.

Schedule Page: 112 Line No.: 3 Column: c

	Total	East	West
Total of Preferred Stock	43,000,000	43,000,000	0

EAST:

Page 106 lines 16, 19 Amount stipulated per contract.

Page 106.2 lines 1, 5 Amount stipulated per contract

Schedule Page: 112 Line No.: 3 Column: d

Information on Formula Rates:

EAST:

Page 106 lines 16, 19 Amount stipulated per contract.

Page 106.2 lines 1, 5 Amount stipulated per contract

Schedule Page: 112 Line No.: 16 Column: c

	Total	East	West
Total Proprietary Capital	3,773,155,027	3,053,220,505	719,934,522

Information on Formula Rates:

EAST:

Page 106.2 lines 1, 5 Amount stipulated per contract.

Schedule Page: 112 Line No.: 16 Column: d

Information on Formula Rates:

EAST:

Page 106.2 lines 1, 5 Amount stipulated per contract.

Schedule Page: 112 Line No.: 18 Column: c

Information on Formula Rates:

Page 106.2 lines 1, 5 Amount stipulated per contract.

Schedule Page: 112 Line No.: 18 Column: d

Information on Formula Rates:

Page 106.2 lines 1, 5 Amount stipulated per contract.

Schedule Page: 112 Line No.: 21 Column: c

Information on Formula Rates:

EAST:

Page 106 lines 16, 19 Amount stipulated per contract.

Page 106.2 lines 1, 5 Amount stipulated per contract.

Schedule Page: 112 Line No.: 21 Column: d

Information on Formula Rates:

EAST:

Page 106 lines 16, 19 Amount stipulated per contract.

Page 106.2 lines 1, 5 Amount stipulated per contract.

Schedule Page: 112 Line No.: 22 Column: c

	Total	East	West
Total Unamortized Premium on Long-Term Debt	6,432,505	3,570,000	2,862,505

Schedule Page: 112 Line No.: 23 Column: c

	Total	East	West
Total of Unamortized Discount on Long-Term Debt	8,941,217	8,451,562	489,655

Schedule Page: 112 Line No.: 24 Column: c

	Total	East	West
Total of Long-Term Debt	2,962,491,288	2,395,118,438	567,372,850

Schedule Page: 112 Line No.: 60 Column: c

For Form 1 reporting purposes, the following reclassification of debit or credit balance accounts at December 31, 2018 are being included with Account 254 - Other Regulatory Liabilities. The balances are as follows:

Balance in Account 254	1,167,252,181	cr.
Reclass of balances from Account 182.3: Mitigation Incentive Timing - DPU 05-89	314,352	cr.
Reclass of balances from Account 182.3: Pension and PBOP	33,542,425	cr.
Reclass of balances to Account 182.3: Basic Service Adder True up	124,429	dr.
Reclass of balances to Account 182.3: Deferred Transition Rev BECO	639,186	dr.
Reclass of balances from Account 182.3: Deferred Basic Service	4,518,390	cr.
Reclass of balances from Account 182.3: Deferred Transmission Revenues	88,984,023	cr.
Reclass of balances to Account 182.3: Deferred NSTAR Green	128,418	dr.

Reclass of balances from Account 182.3: Reg Asset Revenue Decoupling	717,159	cr.
Reclass of balances from Account 182.3: Deferred DSM Revenue	66,942,442	cr.
Reclass of balances from Account 182.3: Deferred Metering Costs	12,735,130	cr.
Reclass of balances from Account 182.3: Uncollectibles Assoc with Basic Service	181,536	cr.
Reclass of balances to Account 182.3: Protective Hardship Credit	16,332	dr.
Account 254 Being Reported	1,374,279,273	cr.

Schedule Page: 112 Line No.: 60 Column: d

For Form 1 reporting purposes, the following reclassification of debit or credit balance accounts at December 31, 2017 are being included with Account 254 - Other Regulatory Liabilities. The balances are as follows:

Balance in Account 254	1,101,328,663	cr.
Reclass of balances to Account 182.3: Deferred Energy Efficiency	134,250,783	cr.
Reclass of balances from Account 182.3: Transition Reconciliation	5,730,439	cr.
Reclass of balances to Account 182.3: Basic Service Uncollectibles	21,513	dr.
Reclass of balances from Account 182.3: Deferred Transmission Revenues	14,941,252	cr.
Reclass of balances from Account 182.3: Pension and PBOP	40,133,963	cr.
Account 254 Being Reported	1,296,363,587	cr.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	3,359,868,073	3,212,553,594		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,123,315,455	1,924,731,430		
5	Maintenance Expenses (402)	320-323	97,135,001	87,747,982		
6	Depreciation Expense (403)	336-337	268,623,877	265,031,848		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	4,730,484	7,357,498		
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)		47,943,523	34,883,593		
13	(Less) Regulatory Credits (407.4)		-14,398,286	-2,096,422		
14	Taxes Other Than Income Taxes (408.1)	262-263	193,925,747	181,647,591		
15	Income Taxes - Federal (409.1)	262-263	76,519,265	111,203,256		
16	- Other (409.1)	262-263	28,549,669	26,226,916		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	180,177,048	181,008,936		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	141,611,239	72,997,470		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,789,183	-1,766,023		
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)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,891,917,933	2,747,171,979		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		467,950,140	465,381,615		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
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)	
						1
3,359,868,073	3,212,553,594					2
						3
2,123,315,455	1,924,731,430					4
97,135,001	87,747,982					5
268,623,877	265,031,848					6
						7
4,730,484	7,357,498					8
						9
						10
						11
47,943,523	34,883,593					12
-14,398,286	-2,096,422					13
193,925,747	181,647,591					14
76,519,265	111,203,256					15
28,549,669	26,226,916					16
180,177,048	181,008,936					17
141,611,239	72,997,470					18
-1,789,183	-1,766,023					19
						20
						21
						22
						23
						24
2,891,917,933	2,747,171,979					25
467,950,140	465,381,615					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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)		467,950,140	465,381,615		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		848,031	1,036,862		
34	(Less) Expenses of Nonutility Operations (417.1)		595,041	674,950		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-4,266,853	-9,327,855		
37	Interest and Dividend Income (419)		803,850	1,850,186		
38	Allowance for Other Funds Used During Construction (419.1)		15,117,148	10,175,401		
39	Miscellaneous Nonoperating Income (421)		17,869,524	19,546,935		
40	Gain on Disposition of Property (421.1)		547,851	105,077		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		30,324,510	22,711,656		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		389,847	489,566		
46	Life Insurance (426.2)		-210,150	-3,243,667		
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		644,481	731,277		
49	Other Deductions (426.5)		1,004,473	4,426,646		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,828,651	2,403,822		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	336,731	311,528		
53	Income Taxes-Federal (409.2)	262-263	-1,747,842	-1,512,200		
54	Income Taxes-Other (409.2)	262-263	-407,937	-83,848		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	9,676,153	6,609,744		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	84,921	130,457		
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)		7,772,184	5,194,767		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		20,723,675	15,113,067		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		111,682,568	118,552,013		
63	Amort. of Debt Disc. and Expense (428)		3,617,567	3,656,868		
64	Amortization of Loss on Reaquired Debt (428.1)		681,150	681,150		
65	(Less) Amort. of Premium on Debt-Credit (429)		1,501,839	1,631,504		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)			817,168		
68	Other Interest Expense (431)		-1,598,931	-11,528,597		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		7,296,852	4,778,393		
70	Net Interest Charges (Total of lines 62 thru 69)		105,583,663	105,768,705		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		383,090,152	374,725,977		
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)		383,090,152	374,725,977		

Schedule Page: 114 Line No.: 13 Column: c

Ferc Account	Company	Ending Balance
407.4	NSTAR Electric East	$ 335,421
	West	(14,733,707)
407.4 Total		**$ (14,398,286)**

Schedule Page: 114 Line No.: 19 Column: c

Ferc Account	Company	Ending Balance
411.4	NSTAR Electric East	$ (1,151,351)
	West	(637,832)
411.4 Total		**$ (1,789,183)**

Schedule Page: 114 Line No.: 38 Column: c

Ferc Account	Company	Ending Balance
419.1	NSTAR Electric East	$ 14,920,641
	West	196,507
419.1 Total		**$ 15,117,148**

Schedule Page: 114 Line No.: 49 Column: c

Note that for the year ended December 31, 2018, the total amount of Public Education expenses in Account 426.5 includes a transmission related component of $0.

Schedule Page: 114 Line No.: 63 Column: c

Ferc Account	Company	Ending Balance
428	NSTAR Electric East	$ 2,313,452
	West	1,304,115
428 Total		**$ 3,617,567**

Schedule Page: 114 Line No.: 64 Column: c

Ferc Account	Company	Ending Balance
428.1	NSTAR Electric East	$ 606,648
	West Distribution	24,834
	West Transmission	49,668
428.1 Total		**$ 681,150**

FOOTNOTE DATA

Schedule Page: 114 Line No.: 65 Column: c

Ferc Account	Company	Ending Balance
429	NSTAR Electric East	$ 428,400
	West	1,073,439
429 Total		**$ 1,501,839**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		767,478,875	657,385,043
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11	Adjustment undistributed Retained Earnings			
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		387,357,005	384,053,832
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	4.25% Cumulative Preferred Stock		-765,000	(765,000)
25	4.78% Cumulative Preferred Stock		-1,195,000	(1,195,000)
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-1,960,000	(1,960,000)
30	Dividends Declared-Common Stock (Account 438)			
31	200 Shares Outstanding (Dividend to Parent Company)		-228,000,000	(272,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-228,000,000	(272,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		924,875,880	767,478,875
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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)
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)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		924,875,880	767,478,875
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-7,584,838	1,743,016
50	Equity in Earnings for Year (Credit) (Account 418.1)		-4,266,853	(9,327,855)
51	(Less) Dividends Received (Debit)			
52	Transfer to Acct 216			
53	Balance-End of Year (Total lines 49 thru 52)		-11,851,691	(7,584,839)

FOOTNOTE DATA

Schedule Page: 118 Line No.: 29 Column: c

All preferred stock is related to NSTAR Electric East.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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)	383,090,152	374,725,977
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	273,354,361	272,389,346
5	Amortization of Debt Discount and Expense	2,796,878	2,706,514
6	Uncollectible Expense	22,279,299	21,251,537
7	Amortization of Regulatory Assets, Net	62,341,809	36,980,015
8	Deferred Income Taxes (Net)	48,157,041	114,490,753
9	Investment Tax Credit Adjustment (Net)	-1,789,183	-1,766,023
10	Net (Increase) Decrease in Receivables	-27,028,926	-30,092,973
11	Net (Increase) Decrease in Inventory	-11,816,225	-5,243,946
12	Net (Increase) Decrease in Allowances Inventory	-15,202,195	-19,197,339
13	Net Increase (Decrease) in Payables and Accrued Expenses	49,350,605	27,072,289
14	Net (Increase) Decrease in Other Regulatory Assets	54,066,435	18,861,447
15	Net Increase (Decrease) in Other Regulatory Liabilities	65,923,518	-57,854,800
16	(Less) Allowance for Other Funds Used During Construction	15,117,148	10,175,401
17	(Less) Undistributed Earnings from Subsidiary Companies	-4,266,853	-9,327,855
18	Other (provide details in footnote):		
19	Pension and PBOP contributions	-61,751,473	-90,720,640
20	Pension and PBOP Income, Net	-21,697,389	-9,886,418
21	Other, Net	-29,413,207	-14,896,656
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	781,811,205	637,971,537
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-728,525,770	-725,338,830
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-15,117,148	-10,175,401
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-713,408,622	-715,163,429
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	-13,500,000	-2,300,000
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)	-1,282,485	-3,868,512
45	Proceeds from Sales of Investment Securities (a)	1,340,790	3,934,036

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	Other Investments, Net		-1,087
55	Contribution to Equity Method Investment		-3,616,775
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-726,850,317	-721,015,767
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		700,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Capital Contribution from Parent	130,500,000	2,300,000
66	Net Increase in Short-Term Debt (c)	44,500,000	107,500,000
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	175,000,000	809,800,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-400,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Financing Expenses, Net	107,614	-1,795,770
78	Net Decrease in Short-Term Debt (c)		
79	Notes Payable to Associated Companies		-51,000,000
80	Dividends on Preferred Stock	-1,960,000	-1,960,000
81	Dividends on Common Stock	-228,000,000	-272,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-54,852,386	83,044,230
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	108,502	
87			
88	Cash and Cash Equivalents at Beginning of Period	12,944,531	
89			
90	Cash and Cash Equivalents at End of period	13,053,033	

FOOTNOTE DATA

Schedule Page: 120 Line No.: 88 Column: b

FERC PAGE NUMBER	LINE #	TITLE OF ACCOUNT	BALANCE
110	35	Cash (131)	$ -
		Restricted Cash	12,944,531
		Total	$ 12,944,531

See Notes to Financial Statements, Footnotes 1C and 1P.

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

FERC PAGE NUMBER	LINE #	TITLE OF ACCOUNT	BALANCE
110	35	Cash (131)	$ -
		Restricted Cash	13,053,033
		Total	$ 13,053,033

See Notes to Financial Statements, Footnotes 1C and 1P.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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 Commmission 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.

On December 31, 2017, affiliate Western Massachusetts Electric Company, was merged into NSTAR Electric Company. This report reflects the combined company. Additional detail by legacy company is provided in footnotes as needed.

The financial statements have been prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than GAAP. NSTAR Electric's Combined Notes to Financial Statements relate to all of Eversource Energy's subsidiaries, including CL&P and PSNH, and are prepared in conformity with GAAP. Accordingly, certain footnotes are not reflective of NSTAR Electric's financial statements contained herein. Refer to the Glossary of Terms for abbreviations and acronyms used throughout the Combined Notes to Financial Statements. The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

Investments in subsidiaries are unconsolidated and are reported on the equity basis in FERC account 123.1 on page 110 in the FERC Form 1 in accordance with the Uniform System of Accounts prescribed by the FERC. Other general purpose financial statements are prepared on a consolidated basis in accordance with GAAP.

Certain regulatory assets and liabilities are reported on a gross basis in FERC accounts 182 and 254 on pages 111 and 113 in the FERC Form 1 and are reported on a net basis and separated into their current and long-term portions in other general purpose financial statements prepared in accordance with GAAP.

Certain amounts recorded as materials and supplies in FERC account 154 are reported in aggregate as a current asset on page 110 in the FERC Form 1 and are separated into their current and long-term portions in other general purpose financial statements prepared in accordance with GAAP.

Unamortized debt expenses recorded in FERC account 181 are reported as a long-term asset on page 111 in the FERC Form 1 and are reported as a direct deduction from the carrying amount of long-term debt in other general purpose financial statements prepared in accordance with GAAP.

Certain miscellaneous assets and liabilities in FERC accounts 186, 229 and 242 on pages 111, 112 and 113 in the FERC Form 1 are reported as regulatory assets or liabilities in other general purpose financial statements prepared in accordance with GAAP.

Cost of removal obligations are included in the accumulated provision for depreciation in FERC account 108 on page 110 in the FERC Form 1 and are reported as a regulatory liability in other general purpose financial statements prepared in accordance with GAAP.

Accumulated deferred income taxes are reported on a gross basis in FERC accounts 190, 282 and 283 on pages 111 and 113 in the FERC Form 1 and are reported on a net basis in other general purpose financial statements prepared in accordance with GAAP.

Taxes receivable and payable are reported on a gross basis in FERC accounts 143 and 236 on pages 110 and 112 in the FERC Form 1 and tax prepayments are reported in FERC account 165 on page 111 in the FERC Form 1. These amounts are shown on a net basis by taxing jurisdiction as a current asset or liability in other general purpose financial statements prepared in accordance with GAAP.

Long-term debt is reported in aggregate in the FERC Form 1 and is segregated between current and long-term in other general purpose financial statements prepared in accordance with GAAP.

Proprietary capital is reported per final filed accounting entries of NSTAR Electric Company related to the merger of Eversource Energy (formerly Northeast Utilities) and NSTAR under AC13-4 et al. Docket No. EC11-35 in FERC accounts 207, 211, 214, and 216 on pages 112 and 118 in the FERC Form 1 and is not reclassed in other general purpose financial statements prepared in accordance with GAAP.

Certain revenue and expense items are reported on a gross basis in FERC accounts 400, 401, 403, 407, 409, 410 and 411 on pages 114 and 117 in the FERC Form 1 and are reported on a net basis in other general purpose financial statements prepared in accordance with GAAP.

Certain items that are recorded in other income and deductions in FERC accounts 408.2, 417, 419, 421 and 426 and in interest expense in FERC account 431 on page 117 in the FERC Form 1 are reported in operating revenues or operating expenses in other general purpose financial statements prepared in accordance with GAAP.

The nonservice components of pension, SERP and PBOP costs are reported in FERC account 926 within Operating Expenses on page 114 in the FERC Form 1 and are presented as non-operating income/(loss) in other general purpose financial statements prepared in accordance with GAAP. The capitalized portion of these nonservice components are recorded within Utility Plant on page 110 in the FERC Form 1 and are reported as a regulatory asset or liability in other general purpose financial statements prepared in accordance with GAAP.

The impact of revenue decoupling, which is the difference between allowed base distribution revenue and actual revenue collected from customers, is reported in FERC account 407 on page 114 in the FERC Form 1 and is reported in operating revenues in other general purpose financial statements prepared in accordance with GAAP.

GAAP requires that public entities report certain information about operating segments in complete sets of financial statements of the entity and certain information about their products and services. GAAP requires disclosure of a measure of segment profit or loss, certain specific revenue and expense items, and segment assets along with reconciliations of amounts disclosed for segments to corresponding amounts in the entity's general purpose financial statements. These disclosures are not required for FERC reporting purposes.

NSTAR Electric has evaluated events subsequent to December 31, 2018 through the issuance of the GAAP financial statements on February 26, 2019, and has updated such evaluation for disclosure purposes through April 16, 2019 and did not identify any such events that required disclosure under this guidance.

See "Index to the Combined Notes to Financial Statements" for a listing of applicable notes for NSTAR Electric.

Index to the Combined Notes to Financial Statements
The notes to the financial statements that follow are a combined presentation. The following list indicates the registrants to which the footnotes apply:

Registrant	Applicable Notes
The Connecticut Light and Power Company	1 (A - C, E – K, M - Q), 2, 3, 4, 6, 7, 8, 9, 10 (A – D), 11, 12 (A – E, G), 14, 15, 16, 17, 18, 19, 22, 25
NSTAR Electric Company	1 (A - C, E, F, H, I, K, M, N, P, Q), 2, 3, 6, 7, 8, 9, 10 (A – D), 11, 12 (A – G), 14, 15, 16, 17, 18, 19, 22, 25
Public Service Company of New Hampshire	1 (A - C, E, F, H, I, K – N, P, Q), 2, 3, 6, 7, 8, 9, 10 (A – D), 11, 12 (A – E, G), 13, 14, 15, 16, 17, 18, 22, 25

EVERSOURCE ENERGY AND SUBSIDIARIES
THE CONNECTICUT LIGHT AND POWER COMPANY
NSTAR ELECTRIC COMPANY AND SUBSIDIARY
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

COMBINED NOTES TO FINANCIAL STATEMENTS

Refer to the Glossary of Terms included in this combined Annual Report on Form 10-K for abbreviations and acronyms used throughout the combined notes to the financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. About Eversource, CL&P, NSTAR Electric and PSNH

Eversource Energy is a public utility holding company primarily engaged, through its wholly-owned regulated utility subsidiaries, in the energy delivery business. Eversource Energy's wholly-owned regulated utility subsidiaries consist of CL&P, NSTAR Electric and PSNH (electric utilities), Yankee Gas and NSTAR Gas (natural gas utilities) and Aquarion (water utilities). Eversource provides energy delivery and/or water service to approximately four million electric, natural gas and water customers through eight regulated utilities in Connecticut, Massachusetts and New Hampshire.

Eversource, CL&P, NSTAR Electric and PSNH are reporting companies under the Securities Exchange Act of 1934. Eversource Energy is a public utility holding company under the Public Utility Holding Company Act of 2005. Arrangements among the regulated electric companies and other Eversource companies, outside agencies and other utilities covering interconnections, interchange of electric power and sales of utility property are subject to regulation by the FERC. Eversource's regulated companies are subject to regulation of rates, accounting and other matters by the FERC and/or applicable state regulatory commissions (the PURA for CL&P, Yankee Gas and Aquarion, the DPU for NSTAR Electric, NSTAR Gas and Aquarion, and the NHPUC for PSNH and Aquarion).

CL&P, NSTAR Electric and PSNH furnish franchised retail electric service in Connecticut, Massachusetts and New Hampshire. Yankee Gas and NSTAR Gas are engaged in the distribution and sale of natural gas to customers within Connecticut and Massachusetts, respectively. Aquarion is engaged in the collection, treatment and distribution of water in Connecticut, Massachusetts and New Hampshire. CL&P, NSTAR Electric and PSNH's results include the operations of their respective distribution and transmission businesses. The distribution business also includes the results of NSTAR Electric's solar power facilities and PSNH's generation facilities prior to sale in 2018. PSNH completed the sales of its thermal generation assets on January 10, 2018 and its hydroelectric generation assets on August 26, 2018. As of December 31, 2018, PSNH does not own any electric generation facilities. See Note 13, "Generation Asset Sale," for further information.

Eversource also has a regulated subsidiary, NPT, which was formed to construct, own and operate the Northern Pass line, a HVDC transmission line from Québec to New Hampshire under development that will interconnect with a new HVDC transmission line being developed by a transmission subsidiary of HQ.

Eversource Service, Eversource's service company, and several wholly-owned real estate subsidiaries of Eversource, provide support services to Eversource, including its regulated companies. Eversource holds several equity ownership interests, which are accounted for under the equity method. Eversource also consolidates the operations of CYAPC and YAEC, both of which are inactive regional nuclear generation companies engaged in the long-term storage of their spent nuclear fuel.

B. Basis of Presentation

The consolidated financial statements of Eversource, NSTAR Electric and PSNH include the accounts of each of their respective subsidiaries. Intercompany transactions have been eliminated in consolidation. The accompanying consolidated financial statements of Eversource, NSTAR Electric and PSNH and the financial statements of CL&P are herein collectively referred to as the "financial statements."

The preparation of the 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 liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Eversource consolidates CYAPC and YAEC because CL&P's, NSTAR Electric's and PSNH's combined ownership and voting interests in each of these entities is greater than 50 percent. Intercompany transactions between CL&P, NSTAR Electric, PSNH and the CYAPC and YAEC companies have been eliminated in consolidation of the Eversource financial statements.

Eversource's utility subsidiaries' electric, natural gas and water distribution and transmission businesses, are subject to rate-regulation that is based on cost recovery and meets the criteria for application of accounting guidance for entities with rate-regulated operations, which considers the effect of regulation on the differences in the timing of the recognition of certain revenues and expenses from those of other businesses and industries. See Note 2, "Regulatory Accounting," for further information.

Eversource's consolidated financial information includes the results of Aquarion and its subsidiaries beginning from the date of the acquisition on December 4, 2017.

Certain reclassifications of prior year data were made in the accompanying financial statements to conform to the current year presentation.

In accordance with accounting guidance on noncontrolling interests in consolidated financial statements, the Preferred Stock of CL&P and the Preferred Stock of NSTAR Electric, which are not owned by Eversource or its consolidated subsidiaries and are not subject to mandatory redemption, have been presented as noncontrolling interests in the financial statements of Eversource. The Preferred Stock of CL&P and the Preferred Stock of NSTAR Electric are considered to be temporary equity and have been classified between liabilities and permanent shareholders' equity on the balance sheets of Eversource, CL&P and NSTAR Electric due to a provision in the preferred stock agreements of both CL&P and NSTAR Electric that grant preferred stockholders the right to elect a majority of the CL&P and NSTAR Electric Boards of Directors, respectively, should certain conditions exist, such as if preferred dividends are in arrears for a specified amount of time. The Net Income reported in the statements of income and cash flows represents net income prior to apportionment to noncontrolling interests, which is represented by dividends on preferred stock of CL&P and NSTAR Electric.

As of both December 31, 2018 and 2017, Eversource's carrying amount of goodwill was approximately $4.4 billion. Eversource performs an assessment for possible impairment of its goodwill at least annually. Eversource completed its annual goodwill impairment test for each of its reporting units as of October 1, 2018 and determined that no impairment exists. See Note 24B, "Acquisition of Aquarion and Goodwill - Goodwill," for further information.

C. Accounting Standards

Accounting Standards Issued but Not Yet Effective: In February 2016, the FASB issued Accounting Standards Update ("ASU") 2016-02, *Leases (Topic 842)*, which changes existing lease accounting guidance and is required to be applied in the first quarter of 2019. The requirements of the new leases standard include balance sheet recognition of leases deemed to be operating leases and additional disclosure requirements. The recognition, measurement and presentation of expenses and cash flows are not significantly changed. The Company implemented the new leases standard in the first quarter of 2019 and applied the Topic 842 lease criteria to new leases and lease renewals entered into effective on or after January 1, 2019.

In July 2018, the FASB issued ASU 2018-11, *Leases (Topic 842) - Targeted Improvements*, allowing a transition method to adopt the new leases standard on a prospective basis as of the adoption date, with prior periods presented in the financial statements continuing to follow existing lease accounting guidance under Topic 840 (Leases) in the accounting literature. The Company adopted the prospective transition method allowed in ASU 2018-11.

The Company has decided to elect the practical expedient package whereby it does not need to reassess whether or not an existing contract is or contains a lease or whether a lease is an operating or capital lease, and it does not need to reassess initial direct costs for leases. The Company has also elected the practical expedient to not reevaluate land easements existing at adoption if they were not previously accounted for as leases.

The Company determined the impact the ASUs will have on its financial statements by reviewing its lease population and identifying lease data needed for the disclosure requirements. The Company implemented a new lease accounting system in 2019 to ensure ongoing compliance with the ASU's requirements. Eversource recognized approximately $60 million, which includes approximately $25 million at NSTAR Electric, approximately $1 million at CL&P and approximately $1 million at PSNH, of operating lease liabilities and right-of-use assets on their respective balance sheets upon transition at January 1, 2019. Implementation of the new guidance will not have an impact on each company's results of operations and cash flows.

Accounting Standards Recently Adopted: On January 1, 2018, Eversource, CL&P, NSTAR Electric and PSNH adopted ASU 2014-09, *Revenue from Contracts with Customers*, which amended existing revenue recognition guidance, using the modified retrospective method (cumulatively at the date of initial application) applying it only to contracts that were not complete at January 1, 2018. Under this method of adoption, prior year reported results were not restated. Implementation of the ASU did not have a material effect on the results of operations, financial position or cash flows of Eversource, CL&P, NSTAR Electric or PSNH. See Note 22, "Revenues," for further information.

The Company identified an item that was accounted for differently under the new revenue guidance, as compared to the previously existing guidance. As a result of applying guidance on the unit of account under the new standard, purchases of power from and sales of power to ISO-New England are now accounted for net by the hour, rather than net by the month. This change increased Operating Revenues and Purchased Power, Fuel and Transmission by $22.8 million for the year ended December 31, 2018, with no impact on net income.

On January 1, 2018, Eversource adopted ASU 2016-01, *Financial Instruments - Overall: Recognition and Measurement of Financial Assets and Liabilities*. The ASU removed the available-for-sale designation for equity securities, whereby changes in fair value were previously recorded in accumulated other comprehensive income within shareholders' equity, and required changes in fair value of all equity securities to be recorded in earnings effective January 1, 2018. There was no cumulative effect of adoption. Unrealized losses recorded in Other Income, Net were $4.3 million for the year ended December 31, 2018. For further information, see Note 5, "Marketable Securities," to the financial statements.

On January 1, 2018, Eversource, CL&P, NSTAR Electric and PSNH adopted ASU 2017-07, *Compensation – Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. The ASU required separate presentation of service cost from other components of net pension, SERP and PBOP costs, with the other components presented as non-operating income and not subject to capitalization. The ASU has been applied retrospectively for the separate presentation in the income statement of service costs and other components and prospectively in the balance sheet for the capitalization of only the service cost component. As of December 31, 2018, the non-service cost components of net pension, SERP and PBOP costs that were not capitalized in plant were recorded as an increase to regulatory liabilities of $39.8 million, as these amounts continue to be included in rates. See Note 1N, "Summary of Significant Accounting Policies - Other Income, Net," to the financial statements for the portion of pension, SERP and PBOP costs that are presented as non-operating income for the years ended December 31, 2018, 2017 and 2016. For the year ended December 31, 2017, the amounts, which were previously presented within Operations and Maintenance expense on the statements of income, totaled $29.9 million at Eversource, $1.8 million at CL&P, $19.2 million at NSTAR Electric and $5.9 million at PSNH, and have been retrospectively presented within Other Income, Net. For the year ended December 31, 2016, these amounts were $18.6 million at Eversource, $0.7 million at CL&P, $10.5 million at NSTAR Electric and $6.2 million at PSNH.

On January 1, 2018, Eversource, CL&P, NSTAR Electric and PSNH adopted two accounting standards relating to the statement of cash flows; ASU 2016-15, *Classification of Certain Cash Receipts and Cash Payments,* and ASU 2016-18, *Restricted Cash.* As a result of implementing ASU 2016-15, dividends from equity method investments of $19.1 million, $20.0 million, and $0.7 million for the years ended December 31, 2018, 2017, and 2016, respectively, are presented in operating activities at Eversource, for which the 2017 and 2016 amounts were previously classified in investing activities. ASU 2016-18 required that the statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash and restricted cash equivalents. Both standards were applied retrospectively, as required, and neither had a material impact on Eversource's, CL&P's, NSTAR Electric's or PSNH's statements of cash flows. See Note 1P, "Summary of Significant Accounting Policies - Supplemental Cash Flow Information," to the financial statements for a reconciliation of cash and cash equivalents as reported on the balance sheet to the statement of cash flows, which includes amounts described as restricted cash and restricted cash equivalents.

D. Northern Pass

Northern Pass is Eversource's planned 1,090 MW HVDC transmission line that will interconnect from the Québec-New Hampshire border to Franklin, New Hampshire and an associated alternating current radial transmission line between Franklin and Deerfield, New Hampshire. As of December 31, 2018, our capitalized Northern Pass project costs were approximately $307 million.

In March 2018, the New Hampshire Site Evaluation Committee ("NHSEC") issued a written decision denying Northern Pass' siting application after which the Massachusetts EDCs terminated the selection of, and subsequent contract negotiations with, Northern Pass under the Massachusetts Clean Energy RFP. On April 27, 2018, NPT filed a motion for rehearing with the NHSEC, and on July 12, 2018, the NHSEC issued its written decision denying Northern Pass' motion for rehearing. On August 10, 2018, NPT filed an appeal to the New Hampshire Supreme Court, alleging that the NHSEC failed to follow applicable law in its review of the project. On October 12, 2018, the New Hampshire Supreme Court accepted this appeal. Subsequently, the NHSEC transmitted the record of its proceedings to the New Hampshire Supreme Court on December 11, 2018. Briefing of the appeal began on February 4, 2019. The New Hampshire Supreme Court has not set a date for oral argument. NPT intends to continue to pursue NHSEC approval to construct this project.

The March 2018 NHSEC decision denying Northern Pass' siting application caused us to review the recoverability of our Northern Pass project costs in the first quarter of 2018. In this recoverability review, we estimated undiscounted expected project cash flows and compared the result to our estimated project costs to determine whether the recorded amount was recoverable. Our undiscounted cash flows were substantially in excess of our estimated project costs. We completed this analysis and concluded that our project costs were recoverable as of March 31, 2018, based on our expectation that the Northern Pass project remains probable of being placed in service.

Consistent with Eversource's and HQ's long-term relationship to bring clean energy into New England, Eversource and HQ remain committed to Northern Pass and the many benefits this project will bring to our customers and the region. If as a result of future events and changes in circumstances a new recoverability review were to conclude that our project costs are not recoverable, then we would reduce Northern Pass' project costs to the estimated fair value, which could result in most of our $307 million of capitalized project costs being impaired. Such an impairment could have a material adverse effect on our financial position and results of operations.

E. Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and short-term cash investments that are highly liquid in nature and have original maturities of three months or less. At the end of each reporting period, any overdraft amounts are reclassified from Cash and Cash Equivalents to Accounts Payable on the balance sheets.

F. Provision for Uncollectible Accounts

Eversource, including CL&P, NSTAR Electric and PSNH, presents its receivables at estimated net realizable value by maintaining a provision for uncollectible accounts. This provision is determined based upon a variety of judgments and factors, including the application of an estimated uncollectible percentage to each receivable aging category. The estimate is based upon historical collection and write-off experience and management's assessment of collectability from customers. Management continuously assesses the collectability of receivables and adjusts collectability estimates based on actual experience. Receivable balances are written off against the provision for uncollectible accounts when the customer accounts are terminated and these balances are deemed to be uncollectible.

The PURA allows CL&P and Yankee Gas to accelerate the recovery of accounts receivable balances attributable to qualified customers under financial or medical duress (uncollectible hardship accounts receivable) outstanding for greater than 180 days and 90 days, respectively. The DPU allows NSTAR Electric and NSTAR Gas to recover in rates, amounts associated with certain uncollectible hardship accounts receivable. These uncollectible hardship customer account balances are included in Regulatory Assets or Other Long-Term Assets on the balance sheets.

The total provision for both uncollectible accounts and for uncollectible hardship accounts (the uncollectible hardship balance is included in the total provision) is included in Receivables, Net on the balance sheets, and is as follows:

	Total Provision for Uncollectible Accounts		Uncollectible Hardship	
	As of December 31,		As of December 31,	
(Millions of Dollars)	2018	2017	2018	2017
Eversource	$ 212.7	$ 195.7	$ 131.5	$ 122.5
CL&P	88.0	78.9	71.9	65.5
NSTAR Electric	74.5	69.7	42.5	40.3
PSNH	11.1	10.5	—	—

In accordance with new revenue accounting guidance, uncollectible expense associated with customers' accounts receivable included in Operations and Maintenance expense on the statements of income is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2018	2017	2016
Eversource	$ 61.3	$ 44.5	$ 69.5
CL&P	15.8	5.3	17.6
NSTAR Electric	22.3	21.3	31.7
PSNH	6.4	6.7	7.3

G. CL&P Energy Efficiency Loans

In December 2018, CL&P transferred $41.3 million of its energy efficiency customer loan portfolio to two outside lenders in order to make additional loans to customers. CL&P remains the servicer of the loans and will transmit customer payments to the lenders. Under a three-year agreement with the lenders, additional energy efficiency loans will also be transferred with a maximum amount outstanding under this program of $55 million. The transaction did not qualify as a sale for accounting purposes, and the amounts of the loans ($18.5 million and $22.8 million as of December 31, 2018 in current and long-term, respectively), included in Accounts Receivable, Net and Other Long-Term Assets, are offset by Other Current Liabilities and Other Long-Term Liabilities on CL&P's balance sheet.

H. Fuel, Materials, Supplies and Inventory

Fuel, Materials, Supplies and Inventory include natural gas inventory, materials and supplies purchased primarily for construction or operation and maintenance purposes, and RECs. Inventory is valued at the lower of cost or net realizable value. RECs are purchased from suppliers of renewable sources of generation and are used to meet state mandated Renewable Portfolio Standards requirements. The carrying amounts of fuel, materials and supplies, and RECs, which are included in Current Assets on the balance sheets, were as follows:

	As of December 31,							
	2018				2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Fuel	$ 33.1	$ —	$ —	$ —	$ 29.7	$ —	$ —	$ —
Materials and Supplies	126.1	44.5	48.6	24.3	117.1	44.4	45.1	18.5
RECs	78.8	—	65.6	13.2	76.3	4.0	50.4	21.8
Total - Current	$ 238.0	$ 44.5	$ 114.2	$ 37.5	$ 223.1	$ 48.4	$ 95.5	$ 40.3

I. Fair Value Measurements

Fair value measurement guidance is applied to derivative contracts that are not elected or designated as "normal purchases" or "normal sales" ("normal") and to the marketable securities held in trusts. Fair value measurement guidance is also applied to valuations of the investments used to calculate the funded status of pension and PBOP plans, the nonrecurring fair value measurements of nonfinancial assets such as goodwill and AROs, and the estimated fair value of preferred stock, long-term debt and RRBs.

Fair Value Hierarchy: In measuring fair value, Eversource uses observable market data when available in order to minimize the use of unobservable inputs. Inputs used in fair value measurements are categorized into three fair value hierarchy levels for disclosure purposes. The entire fair value measurement is categorized based on the lowest level of input that is significant to the fair value measurement. Eversource evaluates the classification of assets and liabilities measured at fair value on a quarterly basis, and Eversource's policy is to recognize transfers between levels of the fair value hierarchy as of the end of the reporting period. The three levels of the fair value hierarchy are described below:

Level 1 - Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 - Inputs are quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations in which all significant inputs are observable.

Level 3 - Quoted market prices are not available. Fair value is derived from valuation techniques in which one or more significant inputs or assumptions are unobservable. Where possible, valuation techniques incorporate observable market inputs that can be validated to external sources such as industry exchanges, including prices of energy and energy-related products.

Uncategorized - Investments that are measured at net asset value are not categorized within the fair value hierarchy.

Determination of Fair Value: The valuation techniques and inputs used in Eversource's fair value measurements are described in Note 4, "Derivative Instruments," Note 5, "Marketable Securities," Note 6, "Asset Retirement Obligations," Note 10A, "Employee Benefits – Pension Benefits and Postretirement Benefits Other Than Pension," Note 15, "Fair Value of Financial Instruments" and Note 24B, "Acquisition of Aquarion and Goodwill - Goodwill" to the financial statements.

J. Derivative Accounting

Many of the electric and natural gas companies' contracts for the purchase and sale of energy or energy-related products are derivatives. The accounting treatment for energy contracts entered into varies and depends on the intended use of the particular contract and on whether or not the contract is a derivative. For the regulated companies, regulatory assets or regulatory liabilities are recorded to offset the fair values of derivative contracts related to energy and energy-related products, as contract settlements are recovered from, or refunded to, customers in future rates.

The application of derivative accounting is complex and requires management judgment in the following respects: identification of derivatives and embedded derivatives, election and designation of a contract as normal, and determination of the fair value of derivative contracts. All of these judgments can have a significant impact on the financial statements.

The judgment applied in the election of a contract as normal (and resulting accrual accounting) includes the conclusion that it is probable at the inception of the contract and throughout its term that it will result in physical delivery of the underlying product and that the quantities will be used or sold by the business in the normal course of business. If facts and circumstances change and management can no longer support this conclusion, then a contract cannot be considered normal, accrual accounting is terminated, and fair value accounting is applied prospectively.

The fair value of derivative contracts is based upon the contract terms and conditions and the underlying market price or fair value per unit. When quantities are not specified in the contract, the Company determines whether the contract has a determinable quantity by using amounts referenced in default provisions and other relevant sections of the contract. The fair value of derivative assets and liabilities with the same counterparty are offset and recorded as a net derivative asset or liability on the balance sheets.

All changes in the fair value of derivative contracts are recorded as regulatory assets or liabilities and do not impact net income.

For further information regarding derivative contracts, see Note 4, "Derivative Instruments," to the financial statements.

K. Investments

Investments are included in Other Long-Term Assets on the balance sheets and earnings impacts from these equity investments are included in Other Income, Net on the statements of income.

Strategic, Infrastructure and Other Investments: As of December 31, 2018 and 2017, Eversource had investments totaling $463.7 million and $277.6 million, respectively. As of December 31, 2018 and 2017, Eversource's investments included a 50 percent ownership in Bay State Wind, an offshore wind project of $234.3 million and $30.2 million, respectively, a 15 percent ownership interest in a FERC-regulated natural gas transmission business of $155.0 million and $159.6 million, respectively, a 37.2 percent (14.5 percent of which related to NSTAR Electric) ownership interest in two companies that transmit hydro-electricity imported from the Hydro-Quebec system in Canada of $19.5 million and $17.7 million, respectively, other investments totaling $54.9 million and $38.8 million, respectively, and a 40 percent ownership interest in Access Northeast of $31.3 million as of December 31, 2017. NSTAR Electric's investments totaled $7.6 million and $6.9 million, respectively, as of December 31, 2018 and 2017.

Impairment of Access Northeast: Access Northeast is a natural gas pipeline and storage project jointly owned by Eversource, Enbridge, Inc. ("Enbridge") and National Grid plc ("National Grid"), through Algonquin Gas Transmission, LLC ("AGT"). Equity method investments are assessed for impairment when conditions exist that indicate that the fair value of the investment is less than book value. If the decline in value is considered to be other-than-temporary, the investment is written down to its estimated fair value, which establishes a new cost basis in the investment. Impairment evaluations involve a significant degree of judgment and estimation, including identifying circumstances that indicate an impairment may exist and developing undiscounted future cash flows.

In 2015 and 2016, AGT sought to secure long-term natural gas pipeline capacity contracts with EDCs in Massachusetts, Connecticut, New Hampshire, Maine, and Rhode Island. Subsequently, in 2016, the Massachusetts Supreme Judicial Court and the NHPUC each ruled that state statutes precluded the state regulatory agencies from approving those contracts in Massachusetts and New Hampshire, respectively. The New Hampshire Supreme Court overruled the NHPUC decision in May 2018. Legislative changes are needed in Massachusetts to allow the DPU to approve natural gas pipeline capacity contracts. No such changes have occurred during any legislative session to date.

In September 2018, a series of non-Eversource natural gas explosions in eastern Massachusetts resulted in widespread property and system damage, personal injuries, and a fatality. As a result of these events, compounded by the failure to secure Massachusetts legislation to date, we believe there is significant uncertainty around the future timing of, and ability to secure, needed legislative change affecting the natural gas industry and pipeline expansion, which may significantly delay the completion of the Access Northeast project.

Eversource identified the September 2018 natural gas series of explosions, compounded by the adverse legislative environment, as negative evidence that indicated potential impairment. Our impairment assessment used a discounted cash flow approach, including consideration of the severity and duration of any decline in fair value of our investment in the project, and involved significant management judgment and estimation, including projections of the project's discounted cash flows and assumptions about exit price. In the third quarter of 2018, management determined that the future cash flows of the Access Northeast project were uncertain and could no longer be reasonably estimated and that the book value of our equity method investment was not recoverable. As a result, Eversource recorded an other-than-temporary impairment of $32.9 million within Other Income, Net on our statement of income in 2018, which represented the full carrying value of our equity method investment.

Regional Decommissioned Nuclear Companies: CL&P, NSTAR Electric and PSNH own common stock in three regional nuclear generation companies (CYAPC, YAEC and MYAPC, collectively referred to as the "Yankee Companies"), each of which owned a single nuclear generating facility that has been decommissioned. For CL&P, NSTAR Electric and PSNH, the respective investments in CYAPC, YAEC and MYAPC are accounted for under the equity method and are included in Other Long-Term Assets on their respective balance sheets. For CL&P, NSTAR Electric and PSNH, these investments totaled $1.3 million, $0.9 million and $0.3 million as of both December 31, 2018 and 2017. Eversource consolidates CYAPC and YAEC because CL&P's, NSTAR Electric's and PSNH's combined ownership and voting interests in each of these entities is greater than 50 percent. For further information on the Yankee Companies, see Note 12C, "Commitments and Contingencies – Spent Nuclear Fuel Obligations – Yankee Companies," to the financial statements.

Equity in Earnings and Dividends from Equity Method Investments: For the years ended December 31, 2018, 2017 and 2016, Eversource had equity in earnings, net of impairment, of unconsolidated affiliates of $3.8 million, $27.4 million, and $0.2 million, respectively. Eversource received dividends from its equity method investees of $22.3 million, $20.0 million and $0.1 million, respectively, for the years ended December 31, 2018, 2017 and 2016.

2019 Investment - Revolution Wind and South Fork Wind: On February 8, 2019, Eversource and Ørsted entered into a 50-50 partnership for key offshore wind assets in the Northeast. Eversource paid approximately $225 million for a 50 percent interest in Ørsted's Revolution Wind and South Fork Wind power projects, as well as the 257-square-mile tract off the coasts of Massachusetts and Rhode Island, owned by North East Offshore LLC. Upon execution of the transaction, Eversource parent issued a guaranty on behalf of its subsidiary, Eversource Investment LLC. Eversource parent will guarantee, as a primary obligor, the financial obligations, primarily all post-Closing payment obligations of Eversource Investment LLC, under the Sale and Purchase Agreement and an Irrevocable Equity Commitment Letter with Ørsted in an amount not to exceed $127.6 million. Eversource parent's obligations under the guaranty expire upon the full, final and indefeasible payment of the guaranteed obligations.

L. Operating Expenses

Costs related to fuel and natural gas included in Purchased Power, Fuel and Transmission on the statements of income were as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2018**	**2017**	**2016**
Eversource - Natural Gas and Fuel	$ 442.6	$ 432.5	$ 372.2
PSNH - Fuel	7.9	43.4	45.0

PSNH completed the sale of its generation assets in 2018.

M. Allowance for Funds Used During Construction

AFUDC represents the cost of borrowed and equity funds used to finance construction and is included in the cost of the electric, natural gas and water companies' utility plant on the balance sheet. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of Interest Expense, and the AFUDC related to equity funds is recorded as Other Income, Net on the statements of income. AFUDC costs are recovered from customers over the service life of the related plant in the form of increased revenue collected as a result of higher depreciation expense.

The average AFUDC rate is based on a FERC-prescribed formula using the cost of a company's short-term financings and capitalization (preferred stock, long-term debt and common equity), as appropriate. The average rate is applied to average eligible CWIP amounts to calculate AFUDC.

AFUDC costs and the weighted-average AFUDC rates were as follows:

Eversource	For the Years Ended December 31,		
(Millions of Dollars, except percentages)	2018	2017	2016
Borrowed Funds	$ 19.7	$ 12.5	$ 10.8
Equity Funds	44.0	34.4	26.2
Total AFUDC	$ 63.7	$ 46.9	$ 37.0
Average AFUDC Rate	4.9%	5.1%	4.4%

	For the Years Ended December 31,								
	2018			2017			2016		
(Millions of Dollars except percentages)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Borrowed Funds	$ 6.3	$ 7.8	$ 1.3	$ 5.1	$ 4.8	$ 0.7	$ 3.3	$ 5.3	$ 0.8
Equity Funds	12.2	15.6	—	12.1	10.2	—	6.3	10.2	0.3
Total AFUDC	$ 18.5	$ 23.4	$ 1.3	$ 17.2	$ 15.0	$ 0.7	$ 9.6	$ 15.5	$ 1.1
Average AFUDC Rate	5.8%	5.0%	0.7%	6.2%	5.0%	0.7%	4.7%	3.2%	1.0%

N. Other Income, Net

The components of Other Income, Net on the statements of income were as follows:

Eversource	For the Years Ended December 31,		
(Millions of Dollars)	2018	2017	2016
Pension, SERP and PBOP Non-Service Income Components (1)	$ 60.8	$ 29.9	$ 18.6
AFUDC Equity	44.0	34.4	26.2
Equity in Earnings, Net of Impairment (2)	3.8	27.4	0.2
Investment Income/(Loss)	(4.0)	7.5	8.5
Interest Income (3)	18.1	8.3	11.0
Gains on Sales of Property	5.1	—	—
Other	0.6	0.4	—
Total Other Income, Net (1)	$ 128.4	$ 107.9	$ 64.5

	For the Years Ended December 31,								
	2018			2017			2016		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Pension, SERP and PBOP Non-Service Income Components (1)	$ 9.5	$ 36.0	$ 9.9	$ 1.8	$ 19.2	$ 5.9	$ 0.7	$ 10.5	$ 6.2
AFUDC Equity	12.2	15.6	—	12.1	10.2	—	6.3	10.2	0.3
Equity in Earnings	0.1	0.7	—	—	0.3	—	0.1	0.3	—
Investment Income/(Loss)	(3.0)	(0.5)	(0.8)	4.5	2.6	1.6	(1.5)	(0.3)	(0.7)
Interest Income (3)	3.7	0.8	14.1	4.6	1.8	2.2	8.6	0.6	1.8
Gain on Sale of Property	—	0.5	4.4	—	—	—	—	—	—
Other	0.2	—	0.1	—	—	0.1	—	—	—
Total Other Income, Net (1)	$ 22.7	$ 53.1	$ 27.7	$ 23.0	$ 34.1	$ 9.8	$ 14.2	$ 21.3	$ 7.6

(1) As a result of the adoption of new accounting guidance, the non-service related components of pension, SERP and PBOP benefit costs are presented as non-operating income and recorded in Other Income, Net on the statements of income. The 2017 and 2016 amounts, which were previously presented within Operations and Maintenance expense on the statements of income, have been retrospectively presented within Other Income, Net for the years ended December 31, 2017 and 2016. Eversource elected the practical expedient in the accounting guidance that allows the Company to use the amounts disclosed in its Pension Benefits and Postretirement Benefits Other Than Pension footnote for the prior period presentations as the estimation basis for applying the retrospective presentation requirements.

(2) For the year ended December 31, 2018, equity in earnings, net of impairment, of unconsolidated affiliates includes an other-than-temporary impairment of $32.9 million in the Access Northeast project investment. See Note 1K, "Summary of Significant Accounting Policies - Investments," for further information. Equity in earnings includes $17.6 million and $9.7 million of unrealized gains in 2018 and 2017, respectively, and $1.7 million of unrealized losses in 2016 associated with an equity method investment in a renewable energy fund.

(3) See Note 2, "Regulatory Accounting," for interest income recognized in 2018 for the equity return component of carrying charges on storm costs at PSNH.

O. Other Taxes

Eversource's companies that serve customers in Connecticut collect gross receipts taxes levied by the state of Connecticut from their customers. These gross receipts taxes are recorded separately with collections in Operating Revenues and with payments in Taxes Other Than Income Taxes on the statements of income as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2018	2017	2016
Eversource	$ 161.9	$ 157.4	$ 162.7
CL&P	141.4	137.5	145.2

As agents for state and local governments, Eversource's companies that serve customers in Connecticut and Massachusetts collect certain sales taxes that are recorded on a net basis with no impact on the statements of income.

Separate from the amounts above are $46.8 million and $25.4 million of amounts recorded as Taxes Other than Income Taxes in 2018 and 2017, respectively, related to the future remittance to the State of Connecticut of energy efficiency funds collected from customers in Operating Revenues.

These amounts are recorded separately with collections in Operating Revenues and expenses in Taxes Other than Income Taxes on the Eversource and CL&P statements of income.

P. Supplemental Cash Flow Information

Eversource
(Millions of Dollars)

	As of and For the Years Ended December 31,		
	2018	2017	2016
Cash Paid/(Received) During the Year for:			
Interest, Net of Amounts Capitalized	$ 503.2	$ 419.1	$ 398.1
Income Taxes	158.8	30.8	(135.5)
Non-Cash Investing Activities:			
Plant Additions Included in Accounts Payable (As of)	435.9	379.5	301.5

	As of and For the Years Ended December 31,								
	2018			2017			2016		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Cash Paid/(Received) During the Year for:									
Interest, Net of Amounts Capitalized	$ 149.7	$ 122.1	$ 40.5	$ 144.6	$ 124.6	$ 45.9	$ 143.3	$ 112.9	$ 46.5
Income Taxes	66.1	120.0	27.3	68.8	95.5	26.1	(73.9)	66.0	(36.0)
Non-Cash Investing Activities:									
Plant Additions Included in Accounts Payable (As of)	106.1	116.5	81.7	132.5	116.5	44.4	116.2	87.0	37.9

In December 2018, CYAPC paid $145 million to the DOE to partially settle its pre-1983 spent nuclear fuel obligation. In 2016, as a result of damages awarded to the Yankee Companies for spent nuclear fuel lawsuits against the DOE described in Note 12C, "Commitments and Contingencies – Spent Nuclear Fuel Obligations – Yankee Companies," CYAPC and YAEC received total proceeds of $52.2 million, which were classified as operating activities on the Eversource consolidated statements of cash flows. CYAPC returned $6.8 million of these proceeds to its non-affiliated member companies. In addition, CL&P, NSTAR Electric and PSNH received a total distribution of $14.4 million from MYAPC as a result of DOE Phase III proceeds and a distribution from its spent nuclear fuel trust.

The following table reconciles cash and cash equivalents as reported on the balance sheets to the cash, cash equivalents, and restricted cash as reported on the statements of cash flows:

	As of December 31,							
	2018				2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Cash and Cash Equivalents as reported on the Balance Sheets	$ 108.1	$ 87.7	$ 1.6	$ 1.4	$ 38.2	$ 6.0	$ 1.8	$ 0.9
Restricted cash included in:								
Prepayments and Other Current Assets	72.1	3.5	13.0	47.5	24.4	3.1	12.8	0.5
Marketable Securities	25.9	0.4	0.1	0.6	23.3	0.5	0.1	0.8
Other Long-Term Assets	3.2	—	—	3.2	—	—	—	—
Cash, Cash Equivalents, and Restricted Cash reported on the Statements of Cash Flows	$ 209.3	$ 91.6	$ 14.7	$ 52.7	$ 85.9	$ 9.6	$ 14.7	$ 2.2

Restricted cash included in Prepayments and Other Current Assets and Other Long-Term Assets, shown above, primarily represents cash collections related to the PSNH RRB customer charges that are held in trust and required ISO-NE cash deposits. Restricted cash included in Marketable Securities, shown above, represents money market funds held in trusts to fund certain non-qualified executive benefits and restricted trusts to fund CYAPC and YAEC's spent nuclear fuel storage facilities obligations.

As a result of implementing new accounting guidance for the statement of cash flows, the reclassification of the change in restricted cash balances, which was previously classified as operating activities, resulted in a decrease of $28.8 million in the total cash and restricted cash change for the year ended December 31, 2017 and an increase of $32.4 million in the total cash and restricted cash change for the year ended December 31, 2016.

Q. Related Parties

Eversource Service, Eversource's service company, provides centralized accounting, administrative, engineering, financial, information technology, legal, operational, planning, purchasing, and other services to Eversource's companies. The Rocky River Realty Company, Renewable Properties, Inc. and Properties, Inc., three other Eversource subsidiaries, construct, acquire or lease some of the property and facilities used by Eversource's companies.

As of both December 31, 2018 and 2017, CL&P, NSTAR Electric and PSNH had long-term receivables from Eversource Service in the amounts of $25.0 million, $5.5 million and $3.8 million, respectively, which were included in Other Long-Term Assets on the balance sheets. These amounts related to the funding of investments held in trust by Eversource Service in connection with certain postretirement benefits for CL&P, NSTAR Electric and PSNH employees and have been eliminated in consolidation on the Eversource financial statements.

Included in the CL&P, NSTAR Electric and PSNH balance sheets as of December 31, 2018 and 2017 were Accounts Receivable from Affiliated Companies and Accounts Payable to Affiliated Companies relating to transactions between CL&P, NSTAR Electric and PSNH and other subsidiaries that are wholly-owned by Eversource. These amounts have been eliminated in consolidation on the Eversource financial statements.

2. REGULATORY ACCOUNTING

Eversource's utility companies are subject to rate regulation that is based on cost recovery and meets the criteria for application of accounting guidance for rate-regulated operations, which considers the effect of regulation on the timing of the recognition of certain revenues and expenses. The regulated companies' financial statements reflect the effects of the rate-making process. The rates charged to the customers of Eversource's regulated companies are designed to collect each company's costs to provide service, including a return on investment.

Management believes it is probable that each of the regulated companies will recover its respective investments in long-lived assets, including regulatory assets. If management were to determine that it could no longer apply the accounting guidance applicable to rate-regulated enterprises to any of the regulated companies' operations, or if management could not conclude it is probable that costs would be recovered from customers in future rates, the costs would be charged to net income in the period in which the determination is made.

Regulatory Assets: The components of regulatory assets were as follows:

	As of December 31,							
	2018				2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Benefit Costs	$ 1,914.8	$ 424.7	$ 544.4	$ 169.6	$ 2,068.8	$ 469.2	$ 560.7	$ 212.3
Income Taxes, Net	728.6	454.4	105.9	8.3	768.9	453.8	113.2	21.7
Securitized Stranded Costs	608.4	—	—	608.4	—	—	—	—
Deferred Costs from Generation Asset Sale	—	—	—	—	516.1	—	—	516.1
Storm Restoration Costs, Net	576.0	302.6	212.9	60.5	404.8	216.7	146.6	41.5
Regulatory Tracker Mechanisms	316.0	33.2	169.1	67.3	509.9	85.3	273.0	116.4
Derivative Liabilities	356.5	356.5	—	—	367.2	362.3	—	—
Goodwill-related	348.4	—	299.1	—	365.2	—	313.6	—
Asset Retirement Obligations	89.2	32.3	42.2	3.3	101.0	30.3	39.0	17.0
Other Regulatory Assets	208.0	27.0	64.6	12.1	137.4	27.6	78.4	15.8
Total Regulatory Assets	5,145.9	1,630.7	1,438.2	929.5	5,239.3	1,645.2	1,524.5	940.8
Less: Current Portion	514.8	125.2	241.7	67.2	741.9	200.3	333.9	130.1
Total Long-Term Regulatory Assets	$ 4,631.1	$ 1,505.5	$ 1,196.5	$ 862.3	$ 4,497.4	$ 1,444.9	$ 1,190.6	$ 810.7

Benefit Costs: Eversource's Pension, SERP and PBOP Plans are accounted for in accordance with accounting guidance on defined benefit pension and other PBOP plans. The liability (or asset) recorded by the regulated companies to recognize the funded status of their retiree benefit plans is offset by a regulatory asset (or offset by a regulatory liability in the case of a benefit plan asset) in lieu of a charge to Accumulated Other Comprehensive Income/(Loss), reflecting ultimate recovery from customers through rates. The regulatory asset (or regulatory liability) is amortized as the actuarial gains and losses and prior service cost are amortized to net periodic benefit cost for the pension and PBOP plans. All amounts are remeasured annually. Regulatory accounting is also applied to the portions of Eversource's service company costs that support the regulated companies, as these amounts are also recoverable. As these regulatory assets or regulatory liabilities do not represent a cash outlay for the regulated companies, no carrying charge is recovered from customers. The decrease in the regulatory asset balance at PSNH as of December 31, 2018 was due in part to the generation divestiture and the securitization of remaining generation costs.

CL&P, NSTAR Electric and PSNH recover benefit costs related to their distribution and transmission operations from customers in rates as allowed by their applicable regulatory commissions. NSTAR Electric recovers qualified pension and PBOP expenses related to its distribution operations through a rate reconciling mechanism that fully tracks the change in net pension and PBOP expenses each year.

Income Taxes, Net: The tax effect of temporary book-tax differences (differences between the periods in which transactions affect income in the financial statements and the periods in which they affect the determination of taxable income, including those differences relating to uncertain tax positions) is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions and accounting guidance for income taxes. Differences in income taxes between the accounting guidance and the rate-making treatment of the applicable regulatory commissions are recorded as regulatory assets. As these assets are offset by deferred income tax liabilities, no carrying charge is collected. The amortization period of these assets varies depending on the nature and/or remaining life of the underlying assets and liabilities. For further information regarding income taxes, see Note 11, "Income Taxes," to the financial statements.

Securitized Stranded Costs and Deferred Costs from Generation Asset Sale: On May 8, 2018, a subsidiary of PSNH issued $635.7 million of securitized RRBs to finance PSNH's unrecovered remaining costs associated with the divestiture of its generation assets. Securitized regulatory assets, which are not earning an equity return, are being recovered over the amortization period of the associated RRBs. The PSNH RRBs are expected to be repaid by February 1, 2033. The unrecovered costs related to the difference between the carrying value and the fair value less costs to sell PSNH's thermal generation assets, and were reflected as Deferred Costs from Generation Asset Sale in the table above as of December 31, 2017. As of December 31, 2018, these costs are reflected in the Securitized Stranded Costs balance. For further information, see Note 13, "Generation Asset Sale."

Storm Restoration Costs, Net: The storm restoration cost deferrals relate to costs incurred for storm events at CL&P, NSTAR Electric and PSNH that each company expects to recover from customers. A storm must meet certain criteria to qualify for deferral and recovery with the criteria specific to each state jurisdiction and utility company. Once a storm qualifies for recovery, all qualifying expenses incurred during storm restoration efforts are deferred and recovered from customers. Costs for storms that do not meet the specific criteria are expensed as incurred. In addition to storm restoration costs, CL&P and PSNH are each allowed to recover pre-staging storm costs. Management believes storm restoration costs deferred were prudently incurred and meet the criteria for specific cost recovery in Connecticut, Massachusetts and New Hampshire, and that recovery from customers is probable through the applicable regulatory recovery processes. Each electric utility company either recovers a carrying charge on its deferred storm restoration cost regulatory asset balance or the regulatory asset balance is included in rate base.

In 2018, several significant storms caused extensive damage to our electric distribution systems and significant customer outages across all three states. These storms resulted in deferred storm restoration costs of approximately $266 million ($148 million for CL&P, $94 million for NSTAR Electric, and $24 million for PSNH), which were reflected in Storm Restoration Costs, Net in the table above as of December 31, 2018.

On September 17, 2018, the NHPUC approved the recovery of $49 million, plus carrying charges, in storm costs incurred from August 2011 through March 2013 and the transfer of funding from PSNH’s major storm reserve to offset those costs. The costs of these storms (excluding the equity return component of the carrying charges) were deferred as regulatory assets, and the funding reserve collected from customers was accrued as a regulatory liability. The storm cost deferral is separate from the major storm funding reserve that is being collected from customers. As a result of the duration of time between incurring storm costs in August 2011 through March 2013 and final approval from the NHPUC in 2018, PSNH recognized $8.7 million (pre-tax) for the equity return component of the carrying charges, which have been collected from customers, within Other Income, Net on our statement of income in 2018. Storm costs incurred from December 2013 through April 2016 have been audited by the NHPUC staff and are pending NHPUC approval.

Regulatory Tracker Mechanisms: The regulated companies' approved rates are designed to recover costs incurred to provide service to customers. The regulated companies recover certain of their costs on a fully-reconciling basis through regulatory commission-approved tracking mechanisms. The differences between the costs incurred (or the rate recovery allowed) and the actual revenues are recorded as regulatory assets (for undercollections) or as regulatory liabilities (for overcollections) to be included in future customer rates each year. Carrying charges are recovered in rates on all material regulatory tracker mechanisms.

CL&P, NSTAR Electric and PSNH each recover, on a fully reconciling basis, the costs associated with the procurement of energy, transmission related costs from FERC-approved transmission tariffs, energy efficiency programs, low income assistance programs, certain uncollectible accounts receivable for hardship customers, and restructuring and stranded costs as a result of deregulation, and additionally for the Massachusetts utilities, pension and PBOP benefits and net metering for distributed generation. Energy procurement costs at NSTAR Electric include the costs related to its solar power facilities.

CL&P, NSTAR Electric (effective February 1, 2018 as a result of a DPU-approved rate case decision), Yankee Gas (effective November 15, 2018 as a result of a PURA-approved rate case settlement agreement) and NSTAR Gas each have a regulatory commission approved revenue decoupling mechanism. Distribution revenues are decoupled from customer sales volumes, where applicable, which breaks the relationship between sales volumes and revenues recognized. Each company reconciles its annual base distribution rate recovery amount to the pre-established levels of baseline distribution delivery service revenues. Any difference between the allowed level of distribution revenue and the actual amount realized during a 12-month period is adjusted through rates in the following period.

Derivative Liabilities: Regulatory assets are recorded as an offset to derivative liabilities and relate to the fair value of contracts used to purchase energy and energy-related products that will be recovered from customers in future rates. These assets are excluded from rate base and are being recovered as the actual settlements occur over the duration of the contracts. See Note 4, "Derivative Instruments," to the financial statements for further information on these contracts.

Goodwill-related: The goodwill regulatory asset originated from a 1999 transaction, and the DPU allowed its recovery in NSTAR Electric and NSTAR Gas rates. This regulatory asset is currently being amortized and recovered from customers in rates without a carrying charge over a 40-year period, and as of December 31, 2018, there were 21 years of amortization remaining.

Asset Retirement Obligations: The costs associated with the depreciation of the regulated companies' ARO assets and accretion of the ARO liabilities are recorded as regulatory assets in accordance with regulatory accounting guidance. The regulated companies' ARO assets, regulatory assets and liabilities offset and are excluded from rate base. These costs are being recovered over the life of the underlying property, plant and equipment.

Other Regulatory Assets: Other Regulatory Assets primarily include contractual obligations associated with the remaining nuclear fuel storage costs of the CYAPC, YAEC and MYAPC nuclear facilities, environmental remediation costs, losses associated with the reacquisition or redemption of long-term debt, certain uncollectible accounts receivable for hardship customers, certain merger-related costs allowed for recovery, water tank painting costs, and various other items.

Regulatory Costs in Long-Term Assets: Eversource's regulated companies had $122.9 million (including $42.1 million for CL&P, $49.3 million for NSTAR Electric and $12.2 million for PSNH) and $105.8 million (including $18.2 million for CL&P, $42.7 million for NSTAR Electric and $27.2 million for PSNH) of additional regulatory costs as of December 31, 2018 and 2017, respectively, that were included in long-term assets on the balance sheets. These amounts represent incurred costs for which recovery has not yet been specifically approved by the applicable regulatory agency. However, based on regulatory policies or past precedent on similar costs, management believes it is probable that these costs will ultimately be approved and recovered from customers in rates.

Equity Return on Regulatory Assets: For rate-making purposes, the regulated companies recover the carrying costs related to their regulatory assets. For certain regulatory assets, the carrying cost recovered includes an equity return component. This equity return, which is not recorded on the balance sheets, totaled $0.7 million and $1.0 million for CL&P as of December 31, 2018 and 2017, respectively. These carrying costs will be recovered from customers in future rates. As of December 31, 2018 and 2017, this equity return, which is not recorded on the balance sheets, totaled $12.0 million and $42.0 million, respectively, for PSNH. The 2017 amount included $25 million of equity return on the Clean Air Project costs that PSNH had agreed not to bill customers as part of the generation divestiture settlement agreement. PSNH sold its generation assets in 2018.

Regulatory Liabilities: The components of regulatory liabilities were as follows:

	As of December 31,							
	2018				2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
EDIT due to Tax Cuts and Jobs Act	$ 2,883.0	$ 1,031.0	$ 1,103.7	$ 396.4	$ 2,882.0	$ 1,031.6	$ 1,087.9	$ 405.1
Cost of Removal	521.0	39.9	307.1	22.1	502.1	23.2	293.8	37.9
Benefit Costs	91.2	—	76.9	—	132.3	—	112.6	—
Regulatory Tracker Mechanisms	309.0	89.5	163.7	48.3	136.7	34.6	77.8	5.0
AFUDC - Transmission	70.7	47.4	23.3	—	67.1	48.8	18.3	—
Revenue Subject to Refund due to Tax Cuts and Jobs Act	24.6	—	—	12.6	—	—	—	—
Other Regulatory Liabilities	80.2	24.0	29.2	4.2	45.2	12.9	3.7	2.7
Total Regulatory Liabilities	3,979.7	1,231.8	1,703.9	483.6	3,765.4	1,151.1	1,594.1	450.7
Less: Current Portion	370.2	109.6	190.6	55.5	128.1	39.0	79.6	6.3
Total Long-Term Regulatory Liabilities	$ 3,609.5	$ 1,122.2	$ 1,513.3	$ 428.1	$ 3,637.3	$ 1,112.1	$ 1,514.5	$ 444.4

EDIT due to Tax Cuts and Jobs Act: Pursuant to the "Tax Cuts and Jobs Act" (the "Act"), which became law on December 22, 2017, Eversource remeasured its existing deferred federal income tax balances as of December 31, 2017 to reflect the decrease in the U.S. federal corporate income tax rate from 35 percent to 21 percent. The remeasurement resulted in provisional regulated excess accumulated deferred income tax (excess ADIT or EDIT) liabilities that will benefit our customers in future periods and were recognized as regulatory liabilities on the balance sheet. We estimate that approximately 85 percent of the provisional regulated EDIT liabilities relate to property, plant, and equipment with remaining useful lives estimated to be in excess of 35 years. These amounts are subject to IRS normalization rules and will be returned to customers using the same timing as the remaining useful lives of the underlying assets that gave rise to the ADIT liabilities.

Eversource's regulated companies are in the process of, or will be, refunding the EDIT liabilities to customers based on orders issued by applicable state regulatory commissions. For CL&P, amounts related to the EDIT liabilities will be incorporated as refunds to customers in May 1, 2019 base distribution rates. For NSTAR Electric (effective January 1, 2019) and NSTAR Gas (effective February 1, 2019), refunds related to EDIT will occur in rates through a new reconciling factor. Effective November 15, 2018, Yankee Gas' distribution rates charged to customers began to reflect the refund of EDIT. For PSNH, EDIT refunds will be addressed as part of the next distribution rate case filing. The EDIT balance related to PSNH's divested generation assets has been included as a component of the securitization of the stranded generation assets and has started to be refunded to customers via the Stranded Cost Recovery Charge effective August 1, 2018. For our transmission companies, the refund of excess ADIT to customers will be made based on future guidance from FERC.

Cost of Removal: Eversource's regulated companies currently recover amounts in rates for future costs of removal of plant assets over the lives of the assets. The estimated cost to remove utility assets from service is recognized as a component of depreciation expense, and the cumulative amount collected from customers but not yet expended is recognized as a regulatory liability.

AFUDC - Transmission: Regulatory liabilities were recorded by CL&P and NSTAR Electric for AFUDC accrued on certain reliability-related transmission projects to reflect local rate base recovery. These regulatory liabilities will be amortized over the depreciable life of the related transmission assets.

Revenue Subject to Refund due to Tax Cuts and Jobs Act: Eversource established a regulatory liability, recorded as a reduction to revenue, to reflect the difference between the 35 percent federal corporate income tax rate included in rates charged to customers and the 21 percent federal corporate income tax rate, effective January 1, 2018 as a result of the Tax Cuts and Jobs Act, until rates billed to customers reflect the lower federal tax rate. Effective May 1, 2018, CL&P adjusted rates billed to customers to reflect the lower federal income tax rate prospectively and, as of December 31,

2018, fully refunded its regulatory liability associated with the higher federal corporate income tax rate billed to customers in the period between January 1, 2018 through April 30, 2018. Effective November 15, 2018, Yankee Gas adjusted distribution rates to reflect the lower federal income tax rate prospectively and to refund its regulatory liability associated with the higher federal corporate income tax rate billed to customers in the period between January 1, 2018 through November 14, 2018. Although Yankee Gas' new rates were effective January 1, 2019, the provisions of the settlement agreement took effect November 15, 2018. For NSTAR Electric and NSTAR Gas, a December 2018 DPU order indicated that the DPU will not require a revision to base rates for any potential refunds associated with the higher federal corporate income tax rate billed to customers in the period between January 1, 2018 to the effective dates of each company's rate changes (effective February 1, 2018 for NSTAR Electric and July 1, 2018 for NSTAR Gas). PSNH and Aquarion will refund the overcollection in distribution rates from January 1, 2018 to customers in a future period. PSNH will adjust distribution rates to reflect the prospective lower federal income tax rate effective July 1, 2019, or earlier if a rate case is filed for rates effective prior to July 1, 2019.

Effective January 1, 2018, local transmission service rates were updated to reflect the lower U.S. federal corporate income tax rate that resulted from the act. On June 28, 2018, FERC granted a one-time tariff waiver related to the federal corporate income tax rate so that effective June 1, 2018, the regional transmission service rates reflect the reduced federal corporate income tax rate at 21 percent. The refund of excess ADIT to customers will be made based on future guidance from FERC.

FERC ROE Complaints: As of December 31, 2018, Eversource has a reserve established for the second ROE complaint in the pending FERC ROE complaint proceedings, which was recorded as a regulatory liability and is reflected within Regulatory Tracker Mechanisms in the table above. The cumulative pre-tax reserve (excluding interest) as of December 31, 2018 totaled $39.1 million for Eversource (including $21.4 million for CL&P, $14.6 million for NSTAR Electric and $3.1 million for PSNH). See Note 12E, "Commitments and Contingencies – FERC ROE Complaints," for further information on developments in the pending ROE complaint proceedings.

3. PROPERTY, PLANT AND EQUIPMENT AND ACCUMULATED DEPRECIATION

Utility property, plant and equipment is recorded at original cost. Original cost includes materials, labor, construction overheads and AFUDC for regulated property. The cost of repairs and maintenance is charged to Operations and Maintenance expense as incurred.

The following tables summarize property, plant and equipment by asset category:

Eversource	As of December 31,	
(Millions of Dollars)	2018	2017
Distribution - Electric	$ 15,071.1	$ 14,410.5
Distribution - Natural Gas	3,546.2	3,244.2
Transmission - Electric	10,153.9	9,270.9
Distribution - Water	1,639.8	1,558.4
Solar	164.1	36.2
Utility	30,575.1	28,520.2
Other (1)	778.6	693.7
Property, Plant and Equipment, Gross	31,353.7	29,213.9
Less: Accumulated Depreciation		
Utility	(7,126.2)	(6,846.9)
Other	(336.7)	(286.9)
Total Accumulated Depreciation	(7,462.9)	(7,133.8)
Property, Plant and Equipment, Net	23,890.8	22,080.1
Construction Work in Progress	1,719.6	1,537.4
Total Property, Plant and Equipment, Net	$ 25,610.4	$ 23,617.5

	As of December 31,					
	2018			2017		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Distribution - Electric	$ 6,176.4	$ 6,756.4	$ 2,178.6	$ 5,888.3	$ 6,479.0	$ 2,083.4
Transmission - Electric	4,700.5	4,065.9	1,338.7	4,239.9	3,821.2	1,161.3
Solar	—	164.1	—	—	36.2	—
Property, Plant and Equipment, Gross	10,876.9	10,986.4	3,517.3	10,128.2	10,336.4	3,244.7
Less: Accumulated Depreciation	(2,302.6)	(2,702.0)	(772.9)	(2,239.0)	(2,550.2)	(751.8)
Property, Plant and Equipment, Net	8,574.3	8,284.4	2,744.4	7,889.2	7,786.2	2,492.9
Construction Work in Progress	335.4	510.3	135.7	381.8	460.3	149.4
Total Property, Plant and Equipment, Net	$ 8,909.7	$ 8,794.7	$ 2,880.1	$ 8,271.0	$ 8,246.5	$ 2,642.3

(1) These assets are primarily comprised of building improvements, computer software, hardware and equipment at Eversource Service.

Depreciation of utility assets is calculated on a straight-line basis using composite rates based on the estimated remaining useful lives of the various classes of property (estimated useful life for PSNH distribution and the water utilities). The composite rates, which are subject to approval by the appropriate state regulatory agency, include a cost of removal component, which is collected from customers over the lives of the plant assets and is recognized as a regulatory liability. Depreciation rates are applied to property from the time it is placed in service.

Upon retirement from service, the cost of the utility asset is charged to the accumulated provision for depreciation. The actual incurred removal costs are applied against the related regulatory liability.

The depreciation rates for the various classes of utility property, plant and equipment aggregate to composite rates as follows:

(Percent)	2018	2017	2016
Eversource	2.9%	3.0%	3.0%
CL&P	2.8%	2.8%	2.7%
NSTAR Electric	2.8%	2.9%	2.9%
PSNH	2.8%	3.1%	3.1%

The following table summarizes average remaining useful lives of depreciable assets:

	As of December 31, 2018			
(Years)	Eversource	CL&P	NSTAR Electric	PSNH
Distribution - Electric	34.1	35.4	33.7	32.3
Distribution - Natural Gas	43.8	—	—	—
Transmission - Electric	41.3	38.0	45.3	42.9
Distribution - Water	33.3	—	—	—
Solar	24.9	—	24.9	—
Other	12.9	—	—	—

4. DERIVATIVE INSTRUMENTS

The electric and natural gas companies purchase and procure energy and energy-related products, which are subject to price volatility, for their customers. The costs associated with supplying energy to customers are recoverable from customers in future rates. These regulated companies manage the risks associated with the price volatility of energy and energy-related products through the use of derivative and non-derivative contracts.

Many of the derivative contracts meet the definition of, and are designated as, normal and qualify for accrual accounting under the applicable accounting guidance. The costs and benefits of derivative contracts that meet the definition of normal are recognized in Operating Expenses on the statements of income, as applicable, as electricity or natural gas is delivered.

Derivative contracts that are not designated as normal are recorded at fair value as current or long-term Derivative Assets or Derivative Liabilities on the balance sheets. For the electric and natural gas companies, regulatory assets or regulatory liabilities are recorded to offset the fair values of derivatives, as contract settlement amounts are recovered from, or refunded to, customers in their respective energy supply rates.

The gross fair values of derivative assets and liabilities with the same counterparty are offset and reported as net Derivative Assets or Derivative Liabilities, with current and long-term portions, on the balance sheets. The following table presents the gross fair values of contracts, categorized by risk type, and the net amounts recorded as current or long-term derivative assets or liabilities:

		As of December 31,					
		2018			2017		
(Millions of Dollars)	Fair Value Hierarchy	Commodity Supply and Price Risk Management	Netting (1)	Net Amount Recorded as a Derivative	Commodity Supply and Price Risk Management	Netting (1)	Net Amount Recorded as a Derivative
Current Derivative Assets:							
CL&P	Level 3	9.6	(3.4)	6.2	9.5	(7.1)	2.4
Other	Level 2	$ 1.5	$ (0.9)	$ 0.6	$ —	$ —	$ —
Long-Term Derivative Assets:							
CL&P	Level 3	74.2	(2.3)	71.9	71.9	(5.3)	66.6
Current Derivative Liabilities:							
CL&P	Level 3	(55.1)	—	(55.1)	(54.4)	—	(54.4)
Other	Level 2	—	—	—	(4.5)	—	(4.5)
Long-Term Derivative Liabilities:							
CL&P	Level 3	(379.5)	—	(379.5)	(376.9)	—	(376.9)
Other	Level 2	—	—	—	(0.4)	—	(0.4)

(1) Amounts represent derivative assets and liabilities that Eversource elected to record net on the balance sheets. These amounts are subject to master netting agreements or similar agreements for which the right of offset exists.

The business activities that result in the recognition of derivative assets also create exposure to various counterparties. As of December 31, 2018, Eversource's and CL&P's derivative assets were exposed to counterparty credit risk and contracted with investment grade entities.

For further information on the fair value of derivative contracts, see Note 1I, "Summary of Significant Accounting Policies – Fair Value Measurements," and Note 1J, "Summary of Significant Accounting Policies – Derivative Accounting," to the financial statements.

Derivative Contracts at Fair Value with Offsetting Regulatory Amounts

Commodity Supply and Price Risk Management: As required by regulation, CL&P, along with UI, has capacity-related contracts with generation facilities. CL&P has a sharing agreement with UI, with 80 percent of the costs or benefits of each contract borne by or allocated to CL&P and 20 percent borne by or allocated to UI. The combined capacity of these contracts is 787 MW. The capacity contracts extend through 2026 and obligate both CL&P and UI to make or receive payments on a monthly basis to or from the generation facilities based on the difference between a set capacity price and the capacity market price received in the ISO-NE capacity markets. In addition, CL&P has a contract to purchase 0.1 million MWh of energy per year through 2020.

As of December 31, 2018 and 2017, Eversource had New York Mercantile Exchange ("NYMEX") financial contracts for natural gas futures in order to reduce variability associated with the price of 12.5 million and 9.5 million MMBtu of natural gas, respectively.

For the years ended December 31, 2018, 2017 and 2016, there were losses of $25.0 million, $29.0 million and $125.5 million, respectively, deferred as regulatory costs, which reflect the change in fair value associated with Eversource's derivative contracts.

Fair Value Measurements of Derivative Instruments

Derivative contracts classified as Level 2 in the fair value hierarchy relate to the financial contracts for natural gas futures. Prices are obtained from broker quotes and are based on actual market activity. The contracts are valued using NYMEX natural gas prices. Valuations of these contracts also incorporate discount rates using the yield curve approach.

The fair value of derivative contracts classified as Level 3 utilizes significant unobservable inputs. The fair value is modeled using income techniques, such as discounted cash flow valuations adjusted for assumptions related to exit price. Significant observable inputs for valuations of these contracts include energy and energy-related product prices in future years for which quoted prices in an active market exist. Fair value measurements categorized in Level 3 of the fair value hierarchy are prepared by individuals with expertise in valuation techniques, pricing of energy and energy-related products, and accounting requirements. The future power and capacity prices for periods that are not quoted in an active market or established at auction are based on available market data and are escalated based on estimates of inflation in order to address the full term of the contract.

Valuations of derivative contracts using a discounted cash flow methodology include assumptions regarding the timing and likelihood of scheduled payments and also reflect non-performance risk, including credit, using the default probability approach based on the counterparty's credit rating for assets and the Company's credit rating for liabilities. Valuations incorporate estimates of premiums or discounts that would be required by a market participant to arrive at an exit price, using historical market transactions adjusted for the terms of the contract.

The following is a summary of CL&P's Level 3 derivative contracts and the range of the significant unobservable inputs utilized in the valuations over the duration of the contracts:

	As of December 31,									
	2018					2017				
CL&P	Range				Period Covered	Range				Period Covered
Capacity Prices	$ 4.30	—	7.44	per kW-Month	2022 - 2026	$ 5.00	—	8.70	per kW-Month	2021 - 2026
Forward Reserve	0.75	—	1.78	per kW-Month	2019 - 2024	1.00	—	2.00	per kW-Month	2018 - 2024

Exit price premiums of 4.2 percent through 15.7 percent are also applied to these contracts and reflect the uncertainty and illiquidity premiums that would be required based on the most recent market activity available for similar type contracts.

Significant increases or decreases in future capacity or forward reserve prices in isolation would decrease or increase, respectively, the fair value of the derivative liability. Any increases in risk premiums would increase the fair value of the derivative liability. Changes in these fair values are recorded as a regulatory asset or liability and do not impact net income.

Valuations using significant unobservable inputs: The following table presents changes in the Level 3 category of derivative assets and derivative liabilities measured at fair value on a recurring basis. The derivative assets and liabilities are presented on a net basis.

CL&P *(Millions of Dollars)*	For the Years Ended December 31,	
	2018	**2017**
Derivatives, Net:		
Fair Value as of Beginning of Period	$ (362.3)	$ (420.5)
Net Realized/Unrealized Losses Included in Regulatory Assets and Liabilities	(32.0)	(9.5)
Settlements	37.8	67.7
Fair Value as of End of Period	$ (356.5)	$ (362.3)

5. MARKETABLE SECURITIES

Eversource holds marketable securities that are primarily used to fund certain non-qualified executive benefits. The trusts that hold marketable securities are not subject to regulatory oversight by state or federal agencies. CYAPC and YAEC maintain legally restricted trusts, each of which holds marketable securities, to fund the spent nuclear fuel removal obligations of their nuclear fuel storage facilities. In December 2018, CYAPC paid $145 million from its trust to the DOE to partially settle the pre-1983 spent nuclear fuel obligation.

Equity Securities: In accordance with new accounting guidance, unrealized gains and losses on equity securities are recorded in Other Income, Net on the statements of income. The fair value of equity securities subject to this guidance as of December 31, 2018 and 2017 was $44.0 million and $52.5 million, respectively. For the year ended December 31, 2018, there were unrealized losses of $4.3 million recorded in Other Income, Net related to these equity securities. For the year ended December 31, 2017, the unrealized gains and losses on these equity securities were recorded in Accumulated Other Comprehensive Income on the balance sheet. Dividend income is recorded in Other Income, Net when dividends are declared.

Eversource's equity securities also include CYAPC's and YAEC's marketable securities held in spent nuclear fuel trusts, which had fair values of $200.0 million and $261.3 million as of December 31, 2018 and 2017, respectively. Unrealized gains and losses for these spent nuclear fuel trusts are subject to regulatory accounting treatment and are recorded in Marketable Securities with the corresponding offset to Other Long-Term Liabilities on the balance sheets, with no impact on the statements of income.

Available-for-Sale Debt Securities: The following is a summary of the available-for-sale debt securities, which are recorded at fair value and are included in current and long-term Marketable Securities on the balance sheets.

	As of December 31,							
	2018				2017			
Eversource *(Millions of Dollars)*	**Amortized Cost**	**Pre-Tax Unrealized Gains**	**Pre-Tax Unrealized Losses**	**Fair Value**	**Amortized Cost**	**Pre-Tax Unrealized Gains**	**Pre-Tax Unrealized Losses**	**Fair Value**
Debt Securities	$ 190.0	$ 0.4	$ (4.0)	$ 186.4	$ 284.9	$ 3.2	$ (1.1)	$ 287.0

Eversource's debt securities include CYAPC's and YAEC's marketable securities held in spent nuclear fuel trusts in the amounts of $143.9 million and $242.3 million as of December 31, 2018 and 2017, respectively.

Unrealized gains and losses on available-for-sale debt securities held in Eversource's non-qualified benefit trust are recorded in Accumulated Other Comprehensive Income. There have been no significant unrealized losses, other-than-temporary impairments, or credit losses for the years ended December 31, 2018 or 2017. Factors considered in determining whether a credit loss exists include the duration and severity of the impairment, adverse conditions specifically affecting the issuer, and the payment history, ratings and rating changes of the security. For asset-backed debt securities, underlying collateral and expected future cash flows are also evaluated.

As of December 31, 2018, the contractual maturities of available-for-sale debt securities were as follows:

Eversource *(Millions of Dollars)*	**Amortized Cost**	**Fair Value**
Less than one year (1)	$ 30.5	$ 30.3
One to five years	29.2	28.9
Six to ten years	43.6	42.9
Greater than ten years	86.7	84.3
Total Debt Securities	$ 190.0	$ 186.4

(1) Amounts in the Less than one year category include securities in the CYAPC and YAEC spent nuclear fuel trusts, which are restricted and are classified in long-term Marketable Securities on the balance sheets.

Realized Gains and Losses: Realized gains and losses are recorded in Other Income, Net for Eversource's benefit trust and are offset in Other Long-Term Liabilities for CYAPC and YAEC. Eversource utilizes the specific identification basis method for the Eversource non-qualified benefit trust, and the average cost basis method for the CYAPC and YAEC spent nuclear fuel trusts to compute the realized gains and losses on the sale of marketable securities. For the year ended December 31, 2017, Eversource recognized net realized gains of $9.8 million on the sales of available-for-sale securities held in the benefit trust. The proceeds of the sales were re-invested in the Eversource benefit trust. There were no similar sales for the year ended December 31, 2018.

Fair Value Measurements: The following table presents the marketable securities recorded at fair value on a recurring basis by the level in which they are classified within the fair value hierarchy:

Eversource *(Millions of Dollars)*	**As of December 31,**	
	2018	**2017**
Level 1:		
Mutual Funds and Equities	$ 244.0	$ 313.8
Money Market Funds	25.9	23.3
Total Level 1	$ 269.9	$ 337.1
Level 2:		
U.S. Government Issued Debt Securities (Agency and Treasury)	$ 79.6	$ 70.2
Corporate Debt Securities	39.5	50.9
Asset-Backed Debt Securities	14.0	21.2
Municipal Bonds	19.2	110.7
Other Fixed Income Securities	8.2	10.7
Total Level 2	$ 160.5	$ 263.7
Total Marketable Securities	$ 430.4	$ 600.8

U.S. government issued debt securities are valued using market approaches that incorporate transactions for the same or similar bonds and adjustments for yields and maturity dates. Corporate debt securities are valued using a market approach, utilizing recent trades of the same or similar instruments and also incorporating yield curves, credit spreads and specific bond terms and conditions. Asset-backed debt securities include collateralized mortgage obligations, commercial mortgage backed securities, and securities collateralized by auto loans, credit card loans or receivables. Asset-backed debt securities are valued using recent trades of similar instruments, prepayment assumptions, yield curves, issuance and

maturity dates, and tranche information. Municipal bonds are valued using a market approach that incorporates reported trades and benchmark yields. Other fixed income securities are valued using pricing models, quoted prices of securities with similar characteristics, and discounted cash flows.

6. ASSET RETIREMENT OBLIGATIONS

Eversource, including CL&P, NSTAR Electric and PSNH, recognizes a liability for the fair value of an ARO on the obligation date if the liability's fair value can be reasonably estimated, even if it is conditional on a future event. Settlement dates and future costs are reasonably estimated when sufficient information becomes available. Management has identified various categories of AROs, primarily CYAPC's and YAEC's obligation to dispose of spent nuclear fuel and high level waste, and also certain assets containing asbestos and hazardous contamination. Management has performed fair value calculations reflecting expected probabilities for settlement scenarios.

The fair value of an ARO is recorded as a liability in Other Long-Term Liabilities with a corresponding amount included in Property, Plant and Equipment, Net on the balance sheets. The ARO assets are depreciated, and the ARO liabilities are accreted over the estimated life of the obligation and the corresponding credits are recorded as accumulated depreciation and ARO liabilities, respectively. As the electric and natural gas companies are rate-regulated on a cost-of-service basis, these companies apply regulatory accounting guidance and both the depreciation and accretion costs associated with these companies' AROs are recorded as increases to Regulatory Assets on the balance sheets.

A reconciliation of the beginning and ending carrying amounts of ARO liabilities is as follows:

	As of December 31,							
	2018				2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Balance as of Beginning of Year	$ 419.1	$ 31.5	$ 44.6	$ 25.0	$ 426.4	$ 36.0	$ 42.6	$ 23.5
Liabilities Incurred During the Year	11.3	—	11.3	—	0.2	0.1	0.1	—
Liabilities Settled During the Year	(36.6)	—	—	(21.5)	(19.3)	(1.0)	(0.2)	—
Accretion	25.5	2.0	2.2	0.5	26.3	2.3	2.1	1.5
Revisions in Estimated Cash Flows	46.9	—	14.3	—	(14.5)	(5.9)	—	—
Balance as of End of Year	$ 466.2	$ 33.5	$ 72.4	$ 4.0	$ 419.1	$ 31.5	$ 44.6	$ 25.0

Eversource's amounts include CYAPC and YAEC's AROs of $339.9 million and $301.5 million as of December 31, 2018 and 2017, respectively. The fair value of the ARO for CYAPC and YAEC includes uncertainties of the fuel off-load dates related to the DOE's timing of performance regarding its obligation to dispose of the spent nuclear fuel and high level waste and other assumptions, including discount rates. The incremental asset recorded as an offset to the ARO liability was fully depreciated since the plants have no remaining useful life. Any changes in the ARO liability are recorded with a corresponding offset to the related regulatory asset. The assets held in the CYAPC and YAEC spent nuclear fuel trusts are restricted for settling the ARO and all other nuclear fuel storage obligations. For further information on the assets held in the spent nuclear fuel trusts, see Note 5, "Marketable Securities," to the financial statements.

The increase in the ARO balance at NSTAR Electric for the year ended December 31, 2018 was due to the recording of new liabilities associated with new solar sites placed into service and the replacement of certain distribution cables, and revised remediation costs for existing AROs related to asbestos and hazardous contamination. The decrease in the ARO balance at PSNH for the year ended December 31, 2018 was a result of the generation divestiture and the securitization of remaining generation costs. See Note 13, "Generation Asset Sale," to the financial statements for further information on the PSNH generation divestiture.

7. SHORT-TERM DEBT

Short-Term Debt Borrowing Limits: The amount of short-term borrowings that may be incurred by CL&P, NSTAR Electric and NPT is subject to periodic approval by the FERC. Because the NHPUC has jurisdiction over PSNH's short-term debt, PSNH is not currently required to obtain FERC approval for its short-term borrowings. On November 30, 2017, the FERC granted authorization that allows CL&P to issue total short-term borrowings in an aggregate principal amount not to exceed $600 million outstanding at any one time, through December 31, 2019. On November 30, 2017, the FERC granted authorization that allows NSTAR Electric to issue total short-term borrowings in an aggregate principal amount not to exceed $655 million outstanding at any one time, through December 30, 2019. On December 3, 2018, FERC authorized NPT to issue up to an aggregate of $800 million in short-term debt and long-term debt through December 31, 2020.

PSNH is authorized by regulation of the NHPUC to incur short-term borrowings up to 10 percent of net fixed plant plus an additional $60 million until further ordered by the NHPUC. As of December 31, 2018, PSNH's short-term debt authorization under the 10 percent of net fixed plant test plus $60 million totaled approximately $331 million.

CL&P's certificate of incorporation contains preferred stock provisions restricting the amount of unsecured debt that CL&P may incur, including limiting unsecured indebtedness with a maturity of less than 10 years to 10 percent of total capitalization. As of December 31, 2018, CL&P had $758.1 million of unsecured debt capacity available under this authorization.

Yankee Gas and NSTAR Gas are not required to obtain approval from any state or federal authority to incur short-term debt.

Commercial Paper Programs and Credit Agreements: Eversource parent has a $1.45 billion commercial paper program allowing Eversource parent to issue commercial paper as a form of short-term debt. Eversource parent, CL&P, PSNH, NSTAR Gas and Yankee Gas are also parties to a five-year $1.45 billion revolving credit facility. Effective December 10, 2018, the revolving credit facility's termination date was extended for one additional year to December 8, 2023. The revolving credit facility serves to backstop Eversource parent's $1.45 billion commercial paper program.

NSTAR Electric has a $650 million commercial paper program allowing NSTAR Electric to issue commercial paper as a form of short-term debt. NSTAR Electric is also a party to a five-year $650 million revolving credit facility. Effective December 10, 2018, the revolving credit facility's termination date was extended for one additional year to December 8, 2023. The revolving credit facility serves to backstop NSTAR Electric's $650 million commercial paper program.

The amount of borrowings outstanding and available under the commercial paper programs were as follows:

	Borrowings Outstanding as of December 31,		Available Borrowing Capacity as of December 31,		Weighted-Average Interest Rate as of December 31,	
(Millions of Dollars)	2018	2017	2018	2017	2018	2017
Eversource Parent Commercial Paper Program	$ 631.5	$ 979.3	$ 818.5	$ 470.7	2.77%	1.86%
NSTAR Electric Commercial Paper Program	278.5	234.0	371.5	416.0	2.50%	1.55%

There were no borrowings outstanding on either the Eversource parent or NSTAR Electric revolving credit facilities as of December 31, 2018 or 2017. Eversource's water distribution segment has a $100.0 million revolving credit facility, which expires on August 19, 2019, and there were no amounts outstanding as of December 31, 2018 and $76.0 million outstanding as of December 31, 2017.

Amounts outstanding under the commercial paper programs and revolving credit facility are included in Notes Payable and classified in current liabilities on the Eversource and NSTAR Electric balance sheets as all borrowings are outstanding for no more than 364 days at one time. As a result of the Eversource parent long-term debt issuances on January 8, 2018, the net proceeds of which were used to repay short-term borrowings outstanding under its commercial paper program, $201.2 million of commercial paper borrowings under the Eversource parent commercial paper program were reclassified as Long-Term Debt as of December 31, 2017.

Under the credit facilities described above, Eversource and its subsidiaries must comply with certain financial and non-financial covenants, including a consolidated debt to total capitalization ratio. As of December 31, 2018 and 2017, Eversource and its subsidiaries were in compliance with these covenants. If Eversource or its subsidiaries were not in compliance with these covenants, an event of default would occur requiring all outstanding borrowings by such borrower to be repaid, and additional borrowings by such borrower would not be permitted under its respective credit facility.

We believe the future operating cash flows of Eversource, CL&P, NSTAR Electric and PSNH, along with our existing borrowing availability and access to financial markets for the issuance of new long-term debt, will be sufficient to meet any working capital and future operating requirements, and capital investment forecast opportunities.

Intercompany Borrowings: Eversource parent uses its available capital resources to provide loans to its subsidiaries to assist in meeting their short-term borrowing needs. In addition, growth in Eversource's key business initiatives requires cash infusion to those subsidiaries. Eversource parent records intercompany interest income from its loans to subsidiaries, which is eliminated in consolidation. Intercompany loans from Eversource parent to its subsidiaries are eliminated in consolidation on Eversource's balance sheets. As of December 31, 2018, there were intercompany loans from Eversource parent to PSNH of $57.0 million. As of December 31, 2017, there were intercompany loans from Eversource parent of $69.5 million to CL&P and $262.9 million to PSNH. Intercompany loans from Eversource parent are included in Notes Payable to Eversource Parent and are classified in current liabilities on the respective subsidiary's balance sheets.

8. LONG-TERM DEBT

Details of long-term debt outstanding are as follows:

CL&P *(Millions of Dollars)*	**As of December 31,**	
	2018	**2017**
First Mortgage Bonds:		
7.875% 1994 Series D due 2024	$ 139.8	$ 139.8
5.750% 2004 Series B due 2034	130.0	130.0
5.625% 2005 Series B due 2035	100.0	100.0
6.350% 2006 Series A due 2036	250.0	250.0
5.750% 2007 Series B due 2037	150.0	150.0
6.375% 2007 Series D due 2037	100.0	100.0
5.650% 2008 Series A due 2018	—	300.0
5.500% 2009 Series A due 2019	250.0	250.0
2.500% 2013 Series A due 2023	400.0	400.0
4.300% 2014 Series A due 2044	475.0	475.0
4.150% 2015 Series A due 2045	350.0	350.0
3.200% 2017 Series A due 2027	300.0	300.0
4.000% 2018 Series A due 2048	500.0	—
Total First Mortgage Bonds	3,144.8	2,944.8
Pollution Control Revenue Bonds:		
4.375% Fixed Rate Tax Exempt due 2028	120.5	120.5
Less Amounts due Within One Year	(250.0)	(300.0)
Unamortized Premiums and Discounts, Net	10.2	11.5
Unamortized Debt Issuance Costs	(21.5)	(17.7)
CL&P Long-Term Debt	$ 3,004.0	$ 2,759.1

NSTAR Electric *(Millions of Dollars)*

	As of December 31, 2018	As of December 31, 2017
Debentures:		
5.750% due 2036	$ 200.0	$ 200.0
5.500% due 2040	300.0	300.0
2.375% due 2022	400.0	400.0
4.400% due 2044	300.0	300.0
3.250% due 2025	250.0	250.0
2.700% due 2026	250.0	250.0
3.200% due 2027	700.0	700.0
Total Debentures	2,400.0	2,400.0
Notes:		
5.900% Senior Notes Series B due 2034	50.0	50.0
6.700% Senior Notes Series D due 2037	40.0	40.0
5.100% Senior Notes Series E due 2020	95.0	95.0
3.500% Senior Notes Series F due 2021	250.0	250.0
3.880% Senior Notes Series G due 2023	80.0	80.0
2.750% Senior Notes Series H due 2026	50.0	50.0
Total Notes	565.0	565.0
Less Amounts due Within One Year	—	—
Unamortized Premiums and Discounts, Net	(2.5)	(1.8)
Unamortized Debt Issuance Costs	(17.7)	(19.4)
NSTAR Electric Long-Term Debt	$ 2,944.8	$ 2,943.8

PSNH *(Millions of Dollars)*

	As of December 31, 2018	As of December 31, 2017
First Mortgage Bonds:		
5.600% Series M due 2035	$ 50.0	$ 50.0
6.000% Series O due 2018	—	110.0
4.500% Series P due 2019	150.0	150.0
4.050% Series Q due 2021	122.0	122.0
3.200% Series R due 2021	160.0	160.0
3.500% Series S due 2023	325.0	325.0
Total First Mortgage Bonds	807.0	917.0
Pollution Control Revenue Bonds:		
Adjustable Rate Tax Exempt Series A due 2021	—	89.3
Less Amounts due Within One Year	(150.0)	(110.0)
Unamortized Premiums and Discounts, Net	—	0.2
Unamortized Debt Issuance Costs	(1.8)	(4.1)
PSNH Long-Term Debt	$ 655.2	$ 892.4

OTHER *(Millions of Dollars)*

	As of December 31, 2018	As of December 31, 2017
Yankee Gas - First Mortgage Bonds: 3.020% - 8.480% due 2019 - 2048	$ 470.0	$ 520.0
NSTAR Gas - First Mortgage Bonds: 4.09% - 9.950% due 2020 - 2048	385.0	285.0
Eversource Parent and Other - Notes and Debentures:		
4.500% Debentures due 2019	350.0	350.0
2.500% - 4.250% Senior Notes due 2021 - 2029	4,360.0	3,260.0
Unsecured Notes 3.570% - 6.430% due 2021 - 2037	289.5	290.9
Secured Debt 4.100% - 9.640% due 2021 - 2035	70.7	70.4
Pre-1983 Spent Nuclear Fuel Obligation (CYAPC)	39.5	181.4
Fair Value Adjustment (1)	144.7	172.6
Less Fair Value Adjustment - Current Portion (1)	(36.2)	(35.4)
Less Amounts due in One Year	(401.1)	(104.2)
Commercial Paper Classified as Long-Term Debt	—	201.2
Unamortized Premiums and Discounts, Net	(4.2)	1.5
Unamortized Debt Issuance Costs	(23.2)	(12.8)
Total Other Long-Term Debt	$ 5,644.7	$ 5,180.6
Total Eversource Long-Term Debt	$ 12,248.7	$ 11,775.9

(1) The fair value adjustment amount is the purchase price adjustments, net of amortization, required to record the NSTAR long-term debt at fair value on the date of the 2012 merger and to record the Aquarion long-term debt at fair value on the date of the 2017 acquisition.

Long-Term Debt Issuances and Repayments: The following table summarizes long-term debt issuances and repayments:

(Millions of Dollars)	Issue Date	Issuances/(Repayments)	Maturity Date	Use of Proceeds for Issuances/ Repayment Information
CL&P:				
4.00% 2018 Series A First Mortgage Bonds	March 2018	$ 500.0	April 2048	Repaid long-term debt that matured in 2018 and repaid short-term borrowings
5.65% 2008 Series A First Mortgage Bonds	May 2008	(300.0)	May 2018	Repaid at maturity on May 1, 2018
PSNH:				
6.00% 2008 Series O First Mortgage Bonds	May 2008	(110.0)	May 2018	Repaid at maturity on May 1, 2018
2001 Series A Pollution Control Revenue Bonds	December 2001	(89.3)	May 2021	Redeemed on November 28, 2018 at a redemption price of $89.3 million
Other:				
Eversource Parent 2.50% Series I Senior Notes (1)	January 2018	200.0	March 2021	Repaid short-term borrowings
Eversource Parent 3.30% Series M Senior Notes	January 2018	450.0	January 2028	Repaid long-term debt that matured in 2018
Eversource Parent 3.80% Series N Senior Notes	December 2018	400.0	December 2023	Repaid short-term borrowings
Eversource Parent 4.25% Series O Senior Notes	December 2018	500.0	April 2029	Repaid short-term borrowings
Eversource Parent 1.60% Series G Senior Notes	January 2015	(150.0)	January 2018	Repaid at maturity on January 15, 2018
Eversource Parent 1.45% Series E Senior Notes	May 2013	(300.0)	May 2018	Repaid at maturity on May 1, 2018
Yankee Gas 4.13% Series O First Mortgage Bonds	September 2018	50.0	October 2048	Repaid long-term debt that matured in 2018
Yankee Gas 6.90% Series J First Mortgage Bonds	October 2008	(100.0)	October 2018	Repaid at maturity on October 1, 2018
NSTAR Gas 4.09% Series P First Mortgage Bonds	September 2018	100.0	October 2048	Repaid short-term borrowings

(1) These notes are part of the same series issued by Eversource parent in March 2016. The aggregate outstanding principal amount of these notes is now $450 million.

As a result of the Eversource parent debt issuances in January 2018, $446.8 million of current portion of long-term debt related to two Eversource parent issuances maturing in 2018 and $201.2 million of commercial paper borrowings were reclassified to Long-Term Debt as of December 31, 2017.

Long-Term Debt Issuance Authorizations: On August 1, 2018, the DPU approved NSTAR Gas' request for authorization to issue up to $200 million in long-term debt through December 31, 2019. On December 3, 2018, FERC authorized NPT to issue up to an aggregate of $800 million in short-term debt and long-term debt through December 31, 2020.

Long-Term Debt Provisions: The utility plant of CL&P, PSNH, Yankee Gas, NSTAR Gas and a portion of Aquarion is subject to the lien of each company's respective first mortgage bond indenture. The Eversource parent, NSTAR Electric and certain Aquarion debt is unsecured. Additionally, the long-term debt agreements provide that Eversource and certain of its subsidiaries must comply with certain covenants as are customarily included in such agreements, including equity requirements for NSTAR Electric and NSTAR Gas. Under the equity requirements, NSTAR Electric's and Aquarion's senior notes must maintain a certain consolidated indebtedness to capitalization ratio as of the end of any fiscal quarter and NSTAR Gas' outstanding long-term debt must not exceed equity.

CL&P's obligation to repay the PCRBs is secured by first mortgage bonds. The first mortgage bonds contain similar terms and provisions as the applicable series of PCRBs. If CL&P fails to meet its obligations under the first mortgage bonds, then the holder of the first mortgage bonds (the issuer of the PCRBs) would have rights under the first mortgage bonds. CL&P's tax-exempt PCRBs will be subject to redemption at par on or after September 1, 2021.

Certain secured and unsecured long-term debt securities are callable at redemption price or are subject to make-whole provisions.

Eversource, NSTAR Electric, Yankee Gas and Aquarion have certain long-term debt agreements that contain cross-default provisions. No other debt issuances contain cross-default provisions as of December 31, 2018.

Pre-1983 Spent Nuclear Fuel Obligation: Under the Nuclear Waste Policy Act of 1982, the DOE is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste. CYAPC is obligated to pay the DOE for the costs to dispose of spent nuclear fuel and high-level radioactive waste generated prior to April 7, 1983 (pre-1983 Spent Nuclear Fuel) and recorded an accrual for the full liability thereof to the DOE. This liability accrues interest costs at the 3-month Treasury bill yield rate. For nuclear fuel used to generate electricity prior to April 7, 1983, payment may be made any time prior to the first delivery of spent fuel to the DOE. Fees for disposal of nuclear fuel burned on or after April 7, 1983 were billed to member companies and paid to the DOE.

As of December 31, 2018 and 2017, as a result of consolidating CYAPC, Eversource has consolidated $39.5 million and $181.4 million, respectively, in pre-1983 spent nuclear fuel obligations to the DOE. In December 2018, CYAPC paid $145 million to the DOE to partially settle this obligation. The obligation includes accumulated interest costs of $29.0 million and $132.6 million as of December 31, 2018 and 2017, respectively. CYAPC maintains a trust to fund amounts due to the DOE for the disposal of pre-1983 spent nuclear fuel. For further information, see Note 5, "Marketable Securities," to the financial statements.

Long-Term Debt Maturities: Long-term debt maturities on debt outstanding for the years 2019 through 2023 and thereafter are shown below. These amounts exclude the CYAPC pre-1983 spent nuclear fuel obligation, net unamortized premiums, discounts and debt issuance costs, and other fair value adjustments as of December 31, 2018:

(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
2019	$ 801.1	$ 250.0	$ —	$ 150.0
2020	296.1	—	95.0	—
2021	1,033.5	—	250.0	282.0
2022	1,188.9	—	400.0	—
2023	1,665.2	400.0	80.0	325.0
Thereafter	7,977.7	2,615.3	2,140.0	50.0
Total	$ 12,962.5	$ 3,265.3	$ 2,965.0	$ 807.0

9. RATE REDUCTION BONDS AND VARIABLE INTEREST ENTITIES

Rate Reduction Bonds: PSNH Funding LLC 3 (PSNH Funding) is a bankruptcy remote, special purpose, wholly-owned subsidiary of PSNH. PSNH Funding was formed solely to issue rate reduction bonds (RRBs) to finance PSNH's unrecovered remaining costs associated with the divestiture of its generation assets.

On May 8, 2018, PSNH Funding issued $635.7 million of securitized RRBs in multiple tranches with a weighted average interest rate of 3.66 percent, and final maturity dates ranging from 2026 to 2035. The RRBs are expected to be repaid by February 1, 2033. RRB payments consist of principal and interest and will be paid semi-annually, beginning on February 1, 2019. The RRBs were issued pursuant to a finance order issued by the NHPUC on January 30, 2018 to recover remaining costs resulting from the divestiture of PSNH's generation assets.

The proceeds were used by PSNH Funding to purchase PSNH's stranded cost asset-recovery property, including its vested property right to bill, collect and adjust a non-bypassable stranded cost recovery charge from PSNH's retail customers. The collections will be used to pay principal, interest and other costs in connection with the RRBs. The RRBs are secured by the stranded cost asset-recovery property. Cash collections from the stranded cost recovery charges and funds on deposit in trust accounts are the sole source of funds to satisfy the debt obligation. PSNH is not the owner of the RRBs, and PSNH Funding's assets and revenues are not available to pay PSNH's creditors. The RRBs are non-recourse senior secured obligations of PSNH Funding and are not insured or guaranteed by PSNH or Eversource Energy.

PSNH Funding is considered a variable interest entity (VIE) primarily because the equity capitalization is insufficient to support its operations. PSNH has the power to direct the significant activities of the VIE and is most closely associated with the VIE as compared to other interest holders. Therefore, PSNH is considered the primary beneficiary and consolidates PSNH Funding in its consolidated financial statements. The following tables summarize the impact of PSNH Funding on PSNH's balance sheet and income statement:

(Millions of Dollars)

Balance Sheet:	As of December 31, 2018
Restricted Cash - Current Portion (included in Prepayments and Other Current Assets)	$ 47.5
Restricted Cash - Long-Term Portion (included in Other Long-Term Assets)	3.2
Securitized Stranded Cost (included in Regulatory Assets)	608.4
Other Regulatory Liabilities (included in Regulatory Liabilities)	5.8
Accrued Interest (included in Other Current Liabilities)	14.4
Rate Reduction Bonds - Current Portion	52.3
Rate Reduction Bonds - Long-Term Portion	583.3

(Millions of Dollars)

Income Statement:	For the Year Ended December 31, 2018
Amortization of RRB Principal (included in Amortization of Regulatory Assets, Net)	$ 27.3
Interest Expense on RRB Principal (included in Interest Expense)	14.4

Variable Interest Entities - Other: The Company's variable interests outside of the consolidated group include contracts that are required by regulation and provide for regulatory recovery of contract costs and benefits through customer rates. Eversource, CL&P and NSTAR Electric hold variable interests in VIEs through agreements with certain entities that own single renewable energy or peaking generation power plants, with other independent power producers and with transmission businesses. Eversource, CL&P and NSTAR Electric do not control the activities that are economically significant to these VIEs or provide financial or other support to these VIEs. Therefore, Eversource, CL&P and NSTAR Electric do not consolidate these VIEs.

10. EMPLOYEE BENEFITS

A. Pension Benefits and Postretirement Benefits Other Than Pension

Eversource provides defined benefit retirement plans ("Pension Plans") that cover eligible employees and are subject to the provisions of ERISA, as amended by the PPA of 2006. Eversource's policy is to annually fund the Pension Plans in an amount at least equal to an amount that will satisfy all federal funding requirements. In addition to the Pension Plans, Eversource maintains non-qualified defined benefit retirement plans ("SERP Plans") which provide benefits in excess of Internal Revenue Code limitations to eligible participants consisting of current and retired employees.

Eversource also provides defined benefit postretirement plans ("PBOP Plans") that provide life insurance and a health reimbursement arrangement created for the purpose of reimbursing retirees and dependents for health insurance premiums and certain medical expenses to eligible employees that met certain age and service eligibility requirements. The benefits provided under the PBOP Plans are not vested, and the Company has the right to modify any benefit provision subject to applicable laws at that time. Eversource annually funds postretirement costs through tax deductible contributions to external trusts.

The Pension, SERP and PBOP Plans cover eligible employees, including, among others, employees of the regulated companies. Because the regulated companies recover retiree benefit costs from customers through rates, regulatory assets are recorded in lieu of recording an adjustment to Accumulated Other Comprehensive Income/(Loss) for the funded status of the Pension, SERP and PBOP Plans. Regulatory accounting is also applied to the portions of the Eversource Service retiree benefit costs that support the regulated companies, as these costs are also recovered from customers. Adjustments to the Pension and PBOP Plans funded status for the unregulated companies are recorded on an after-tax basis to Accumulated Other Comprehensive Income/(Loss). For further information, see Note 2, "Regulatory Accounting," and Note 16, "Accumulated Other Comprehensive Income/(Loss)," to the financial statements.

The difference between the actual return and calculated expected return on plan assets for the Pension and PBOP Plans is reflected as a component of unamortized actuarial gains or losses, which are recorded in Regulatory Assets or Accumulated Other Comprehensive Income/(Loss). Unamortized actuarial gains or losses are amortized as a component of pension and PBOP expense over the estimated average future employee service period.

Pension and SERP Plans: The Pension and SERP Plans are accounted for under the multiple-employer approach, with each operating company's balance sheet reflecting its share of the funded status of the plans. Although Eversource maintains marketable securities in a benefit trust, the SERP Plans do not contain any assets. For further information, see Note 5, "Marketable Securities," to the financial statements. The following table provides information on the Pension and SERP Plan benefit obligations, fair values of Pension Plan assets, and funded status:

	Pension and SERP							
	As of December 31, 2018				As of December 31, 2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Change in Benefit Obligation:								
Benefit Obligation as of Beginning of Year	$ (5,936.5)	$ (1,275.2)	$ (1,351.0)	$ (642.2)	$ (5,242.3)	$ (1,170.2)	$ (1,217.3)	$ (572.2)
Service Cost	(84.8)	(21.4)	(17.4)	(11.2)	(71.3)	(18.5)	(15.5)	(9.7)
Interest Cost	(196.4)	(41.8)	(43.5)	(22.0)	(188.0)	(41.6)	(42.7)	(21.2)
Actuarial Gain/(Loss)	414.9	106.1	98.6	39.2	(548.7)	(116.9)	(143.5)	(65.1)
Benefits Paid - Pension	261.8	59.6	66.9	26.2	243.7	63.5	55.4	26.4
Benefits Paid - Lump Sum	14.2	—	7.1	—	18.4	—	6.8	—
Benefits Paid - SERP	6.8	0.3	0.3	0.2	20.4	0.3	0.3	0.3
Employee Transfers	—	12.0	2.5	(0.9)	—	8.2	5.5	(0.7)
Increase due to acquisition of Aquarion	—	—	—	—	(168.7)	—	—	—
Benefit Obligation as of End of Year	$ (5,520.0)	$ (1,160.4)	$ (1,236.5)	$ (610.7)	$ (5,936.5)	$ (1,275.2)	$ (1,351.0)	$ (642.2)
Change in Pension Plan Assets:								
Fair Value of Pension Plan Assets as of Beginning of Year	$ 4,739.5	$ 963.0	$ 1,260.8	$ 539.5	$ 4,076.0	$ 905.5	$ 1,088.3	$ 494.0
Employer Contributions	185.6	41.2	56.5	—	235.2	2.5	85.4	0.8
Actual Return on Pension Plan Assets	(75.2)	(14.2)	(18.7)	(7.6)	589.7	126.7	154.8	70.4
Benefits Paid - Pension	(261.8)	(59.6)	(66.9)	(26.2)	(243.7)	(63.5)	(55.4)	(26.4)
Benefits Paid - Lump Sum	(14.2)	—	(7.1)	—	(18.4)	—	(6.8)	—
Employee Transfers	—	(12.0)	(2.5)	0.9	—	(8.2)	(5.5)	0.7
Increase due to acquisition of Aquarion	—	—	—	—	100.7	—	—	—
Fair Value of Pension Plan Assets as of End of Year	$ 4,573.9	$ 918.4	$ 1,222.1	$ 506.6	$ 4,739.5	$ 963.0	$ 1,260.8	$ 539.5
Funded Status as of December 31st	$ (946.1)	$ (242.0)	$ (14.4)	$ (104.1)	$ (1,197.0)	$ (312.2)	$ (90.2)	$ (102.7)

In 2018, there was an increase to the discount rate used to calculate the funded status of the Eversource pension liability, which resulted in a decrease to Eversource's pension liability of approximately $465 million as of December 31, 2018, which was partially offset by changes in actual plan experience and changes in other assumptions.

In 2017, there was a decrease to the discount rate used to calculate the funded status of the Eversource pension liability, which resulted in an increase to Eversource's pension liability of approximately $390 million as of December 31, 2017.

The pension and SERP Plans' funded status includes the current portion of the SERP liability totaling $8.9 million and $8.4 million as of December 31, 2018 and 2017, respectively, which is included in Other Current Liabilities on the balance sheets.

As of December 31, 2018 and 2017, the accumulated benefit obligation for the Pension and SERP Plans is as follows:

(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
2018	$ 5,070.8	$ 1,031.0	$ 1,144.7	$ 543.1
2017	5,583.6	1,179.2	1,260.1	597.2

The following actuarial assumptions were used in calculating the Pension and SERP Plans' year end funded status:

	Pension and SERP	
	As of December 31,	
	2018	2017
Discount Rate	4.22% — 4.45%	3.43% — 3.75%
Compensation/Progression Rate	3.50%	3.50%

The compensation rate for the Aquarion Plans was 4 percent as of December 31, 2018 and 2017.

Pension and SERP Expense: Eversource charges net periodic pension expense to its subsidiaries based on the actual participant demographic data for each subsidiary's participants. The actual investment return in the trust is allocated to each of the subsidiaries annually in proportion to the investment return expected to be earned during the year. The Company utilizes the spot rate methodology to estimate the discount rate for the service and interest cost components of pension expense, which provides a more precise measurement by matching projected cash flows to the corresponding spot rates on the yield curve.

The components of net periodic benefit expense for the Pension and SERP Plans, prior to amounts capitalized as Property, Plant and Equipment or deferred as regulatory assets for future recovery, are shown below. The service cost component of net periodic benefit expense and the intercompany allocations, less the capitalized portions, are included in Operations and Maintenance expense on the statements of income. The remaining components of net periodic benefit costs are included in Other Income, Net on the statements of income. Pension and SERP expense reflected in the statements of cash flows for CL&P, NSTAR Electric and PSNH does not include the intercompany allocations or the corresponding capitalized and deferred portion, as these amounts are cash settled on a short-term basis.

	Pension and SERP			
	For the Year Ended December 31, 2018			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
Service Cost	$ 84.8	$ 21.4	$ 17.4	$ 11.2
Interest Cost	196.4	41.8	43.5	22.0
Expected Return on Pension Plan Assets	(391.6)	(79.1)	(104.9)	(43.6)
Actuarial Loss	145.7	29.1	41.1	11.6
Prior Service Cost	4.3	1.1	0.2	0.4
Total Net Periodic Benefit Expense/(Income)	$ 39.6	$ 14.3	$ (2.7)	$ 1.6
Intercompany Allocations	N/A	$ 6.1	$ 6.5	$ 1.9

	Pension and SERP			
	For the Year Ended December 31, 2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
Service Cost	$ 71.3	$ 18.5	$ 15.5	$ 9.7
Interest Cost	188.0	41.6	42.7	21.2
Expected Return on Pension Plan Assets	(334.1)	(71.7)	(87.6)	(40.0)
Actuarial Loss	135.2	27.7	41.1	11.6
Prior Service Cost	4.5	1.5	0.6	0.5
Total Net Periodic Benefit Expense	$ 64.9	$ 17.6	$ 12.3	$ 3.0
Intercompany Allocations	N/A	$ 9.8	$ 9.1	$ 3.3

	Pension and SERP			
	For the Year Ended December 31, 2016			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
Service Cost	$ 75.0	$ 18.8	$ 16.3	$ 9.9
Interest Cost	185.5	41.6	42.2	20.7
Expected Return on Pension Plan Assets	(317.9)	(72.1)	(85.1)	(38.6)
Actuarial Loss	125.7	25.4	39.9	9.9
Prior Service Cost	3.6	1.5	0.3	0.5
Total Net Periodic Benefit Expense	$ 71.9	$ 15.2	$ 13.6	$ 2.4
Intercompany Allocations	N/A	$ 13.8	$ 11.4	$ 4.0

The following actuarial assumptions were used to calculate Pension and SERP expense amounts:

	Pension and SERP		
	For the Years Ended December 31,		
	2018	2017	2016
Discount Rate	3.85% — 4.62%	3.20% — 3.90%	3.27% — 4.89%
Expected Long-Term Rate of Return	8.25%	8.25%	8.25%
Compensation/Progression Rate	3.50%	3.50%	3.50%

For the Aquarion Plans, the long-term expected rate of return was 7 percent and the compensation rate was 4 percent for the year ended December 31, 2018.

The following is a summary of the changes in plan assets and benefit obligations recognized in Regulatory Assets and Other Comprehensive Income ("OCI") as well as amounts in Regulatory Assets and OCI that were reclassified as net periodic benefit expense during the years presented:

	Regulatory Assets		OCI	
	For the Years Ended December 31,		For the Years Ended December 31,	
(Millions of Dollars)	2018	2017	2018	2017
Actuarial Losses Arising During the Year	$ 48.6	$ 333.0	$ 0.7	$ 9.3
Actuarial Losses Reclassified as Net Periodic Benefit Expense	(140.1)	(129.5)	(5.6)	(5.7)
Actuarial Losses Securitized as Stranded Costs (1)	(36.7)	—	—	—
Prior Service Cost/(Credit) Arising During the Year	—	1.0	—	(0.4)
Prior Service Cost Reclassified as Net Periodic Benefit Expense	(3.9)	(4.1)	(0.4)	(0.4)
Prior Service Cost Securitized as Stranded Costs (1)	(0.1)	—	—	—

(1) These amounts were reclassified to securitized regulatory assets in connection with the divestiture of PSNH's generation business. For further information see Note 2, "Regulatory Accounting" to the financial statements.

The following is a summary of the remaining Regulatory Assets and Accumulated Other Comprehensive Income amounts that have not been recognized as components of net periodic benefit expense as of December 31, 2018 and 2017, as well as the amounts that are expected to be recognized as components in 2019:

	Regulatory Assets as of December 31,		Expected 2019 Expense	AOCI as of December 31,		Expected 2019 Expense
(Millions of Dollars)	2018	2017		2018	2017	
Actuarial Loss	$ 1,807.6	$ 1,935.8	$ 140.6	$ 80.8	$ 85.7	$ 5.6
Prior Service Cost	6.3	10.3	0.9	1.1	1.5	0.2

PBOP Plans: The PBOP Plans are accounted for under the multiple-employer approach, with each operating company's balance sheet reflecting its share of the funded status of the plans. The following table provides information on the PBOP Plan benefit obligations, fair values of plan assets, and funded status:

	PBOP							
	As of December 31,							
	2018				2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Change in Benefit Obligation:								
Benefit Obligation as of Beginning of Year	$ (948.6)	$ (178.4)	$ (278.6)	$ (101.1)	$ (810.0)	$ (165.0)	$ (270.0)	$ (89.7)
Service Cost	(10.0)	(1.9)	(2.0)	(1.1)	(9.5)	(1.9)	(1.7)	(1.3)
Interest Cost	(30.7)	(5.8)	(8.7)	(3.4)	(27.1)	(5.3)	(8.7)	(3.0)
Actuarial Gain/(Loss)	102.5	14.4	28.4	8.6	(81.8)	(18.5)	(13.2)	(11.9)
Benefits Paid	45.3	10.1	14.5	4.9	41.5	9.9	13.5	4.6
Employee Transfers	—	(0.1)	0.1	0.2	—	2.4	1.5	0.2
Increase due to acquisition of Aquarion	—	—	—	—	(61.7)	—	—	—
Benefit Obligation as of End of Year	$ (841.5)	$ (161.7)	$ (246.3)	$ (91.9)	$ (948.6)	$ (178.4)	$ (278.6)	$ (101.1)
Change in Plan Assets:								
Fair Value of Plan Assets as of Beginning of Year	$ 922.2	$ 135.9	$ 405.5	$ 79.0	$ 815.8	$ 129.2	$ 361.6	$ 73.2
Actual Return on Plan Assets	(36.6)	(5.2)	(17.4)	(2.9)	118.0	18.1	52.9	10.4
Employer Contributions	9.3	—	5.2	—	7.6	—	5.3	—
Benefits Paid	(45.3)	(10.1)	(14.5)	(4.9)	(41.5)	(9.9)	(13.5)	(4.6)
Employee Transfers	—	—	0.3	—	—	(1.5)	(0.8)	—
Increase due to acquisition of Aquarion	—	—	—	—	22.3	—	—	—
Fair Value of Plan Assets as of End of Year	$ 849.6	$ 120.6	$ 379.1	$ 71.2	$ 922.2	$ 135.9	$ 405.5	$ 79.0
Funded Status as of December 31st	$ 8.1	$ (41.1)	$ 132.8	$ (20.7)	$ (26.4)	$ (42.5)	$ 126.9	$ (22.1)

The Eversource funded status includes prepaid assets of $33.4 million and $13.1 million recorded in Other Long-Term Assets and liabilities of $25.3 million and $39.5 million included in Accrued Pension, SERP and PBOP on the balance sheets as of December 31, 2018 and 2017, respectively.

As of December 31, 2018, there was an increase in the discount rate used to calculate the funded status, resulting in a decrease in the Eversource PBOP liability of approximately $88 million.

As of December 31, 2017, there was a decrease in the discount rate used to calculate the funded status, as compared to the discount rate as of December 31, 2016, resulting in an increase to the Eversource PBOP liability of approximately $64 million.

The following actuarial assumptions were used in calculating the PBOP Plans' year end funded status:

	PBOP					
	As of December 31,					
	2018			2017		
Discount Rate	4.38%	—	4.41%	3.55%	—	3.70%

For the Eversource Service PBOP Plan, effective with the plan amendment that standardized plan designs and made benefit changes in August 2016, the health care cost trend rate is no longer applicable. For the Aquarion PBOP Plan, the health care trend rate is a range of 3.5 percent to 6.75 percent, with an ultimate rate of 3.5 percent to 5 percent in 2019 and 2023, for post-65 and pre-65 retirees, respectively.

PBOP Expense: Eversource charges net periodic postretirement benefits expense to its subsidiaries based on the actual participant demographic data for each subsidiary's participants. The actual investment return in the trust each year is allocated to each of the subsidiaries annually in proportion to the investment return expected to be earned during the year. The Company utilizes the spot rate methodology to estimate the discount rate for the service and interest cost components of PBOP expense, which provides a more precise measurement by matching projected cash flows to the corresponding spot rates on the yield curve.

The components of net periodic benefit expense for the PBOP Plans, prior to amounts capitalized as Property, Plant and Equipment or deferred as regulatory assets on the balance sheets, are shown below. The service cost component of net periodic benefit expense and the intercompany allocations, less the capitalized portions, are included in Operations and Maintenance expense on the statements of income. The remaining components of net periodic benefit costs are included in Other Income, Net on the statements of income. PBOP expense reflected in the statements of cash flows for CL&P, NSTAR Electric and PSNH does not include the intercompany allocations or the corresponding capitalized portion, as these amounts are cash settled on a short-term basis.

	PBOP			
	For the Year Ended December 31, 2018			
(Millions of Dollars)	**Eversource**	**CL&P**	**NSTAR Electric**	**PSNH**
Service Cost	$ 10.0	$ 1.9	$ 2.0	$ 1.1
Interest Cost	30.7	5.8	8.7	3.4
Expected Return on Plan Assets	(72.4)	(10.4)	(32.5)	(6.0)
Actuarial Loss	10.3	1.6	2.3	0.7
Prior Service (Credit)/Cost	(23.6)	1.1	(16.9)	0.5
Total Net Periodic Benefit Income	$ (45.0)	$ —	$ (36.4)	$ (0.3)
Intercompany Allocations	N/A	$ (1.0)	$ (1.3)	$ (0.4)

	PBOP			
	For the Year Ended December 31, 2017			
(Millions of Dollars)	**Eversource**	**CL&P**	**NSTAR Electric**	**PSNH**
Service Cost	$ 9.5	$ 1.9	$ 1.7	$ 1.3
Interest Cost	27.1	5.3	8.7	3.0
Expected Return on Plan Assets	(63.7)	(9.7)	(28.6)	(5.5)
Actuarial Loss	9.1	1.0	3.4	0.6
Prior Service (Credit)/Cost	(21.6)	1.1	(17.0)	0.6
Total Net Periodic Benefit Income	$ (39.6)	$ (0.4)	$ (31.8)	$ —
Intercompany Allocations	N/A	$ (0.7)	$ (1.1)	$ (0.5)

	PBOP			
	For the Year Ended December 31, 2016			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
Service Cost	$ 12.2	$ 2.0	$ 3.4	$ 1.3
Interest Cost	32.9	5.3	13.3	2.9
Expected Return on Plan Assets	(62.9)	(10.1)	(28.1)	(5.5)
Actuarial Loss	9.0	1.5	3.3	0.7
Prior Service (Credit)/Cost	(9.1)	0.5	(7.1)	0.2
Total Net Periodic Benefit Income	$ (17.9)	$ (0.8)	$ (15.2)	$ (0.4)
Intercompany Allocations	N/A	$ 0.3	$ (0.1)	$ (0.1)

The following actuarial assumptions were used to calculate PBOP expense amounts:

	PBOP		
	For the Years Ended December 31,		
	2018	2017	2016
Discount Rate	3.28% — 3.94%	3.48% — 4.64%	2.88% — 4.09%
Expected Long-Term Rate of Return	8.25%	8.25%	8.25%

For the Aquarion Plan, the expected long-term rate of return was 7 percent and the health care trend rate was 7 percent for the year ended December 31, 2018.

The following is a summary of the changes in plan assets and benefit obligations recognized in Regulatory Assets and OCI as well as amounts recognized in Regulatory Assets and OCI that were reclassified as net periodic benefit (expense)/income during the years presented:

	Regulatory Assets		OCI	
	For the Years Ended December 31,		For the Years Ended December 31,	
(Millions of Dollars)	2018	2017	2018	2017
Actuarial Losses/(Gains) Arising During the Year	$ 6.4	$ 44.8	$ (1.2)	$ 2.6
Actuarial Losses Reclassified as Net Periodic Benefit Expense	(9.9)	(8.6)	(0.4)	(0.5)
Actuarial Losses Securitized as Stranded Costs (1)	(0.8)	—	—	—
Prior Service (Credit)/Cost Arising During the Year	1.3	(4.0)	—	(0.1)
Prior Service Credit/(Cost) Reclassified as Net Periodic Benefit Income/(Expense)	23.6	22.3	—	(0.7)
Prior Service Cost Securitized as Stranded Costs (1)	(1.3)	—	—	—

(1) These amounts were reclassified to securitized regulatory assets in connection with the divestiture of PSNH's generation business. For further information see Note 2, "Regulatory Accounting" to the financial statements.

The following is a summary of the remaining Regulatory Assets and Accumulated Other Comprehensive Income amounts that have not been recognized as components of net periodic benefit expense as of December 31, 2018 and 2017, as well as the amounts that are expected to be recognized as components in 2019:

	Regulatory Assets as of December 31,		Expected 2019 Expense	AOCI as of December 31,		Expected 2019 Expense
(Millions of Dollars)	2018	2017		2018	2017	
Actuarial Loss	$ 207.3	$ 211.6	$ 9.9	$ 5.0	$ 6.6	$ 0.3
Prior Service (Credit)/Cost	(197.6)	(221.2)	(23.6)	2.6	2.6	0.2

Estimated Future Benefit Payments: The following benefit payments, which reflect expected future service, are expected to be paid by the Pension, SERP and PBOP Plans:

(Millions of Dollars)	2019	2020	2021	2022	2023	2024 - 2028
Pension and SERP	$ 308.5	$ 310.4	$ 318.8	$ 326.6	$ 335.6	$ 1,764.1
PBOP	58.4	58.5	58.6	58.3	57.8	277.4

Eversource Contributions: Based on the current status of the Pension Plans and federal pension funding requirements, Eversource currently expects to make contributions of approximately $112 million in 2019, of which approximately $44 million and $10 million will be contributed by CL&P and PSNH, respectively. The remaining $46 million is expected to be contributed by other Eversource subsidiaries, primarily Eversource Service. Eversource expects to make approximately $11 million in contributions to the PBOP Plan in 2019, of which approximately $6 million will be contributed by NSTAR Electric.

Fair Value of Pension and PBOP Plan Assets: Pension and PBOP funds are held in external trusts. Trust assets, including accumulated earnings, must be used exclusively for Pension and PBOP payments. Eversource's investment strategy for its Pension and PBOP Plans is to maximize the long-term rates of return on these plans' assets within an acceptable level of risk. The investment strategy for each asset category includes a diversification of asset types, fund strategies and fund managers and it establishes target asset allocations that are routinely reviewed and periodically rebalanced. PBOP assets are comprised of assets held in the PBOP Plan trust, as well as specific assets within the Pension Plan trust (401(h) assets). The investment policy and strategy of the 401(h) assets is consistent with that of the defined benefit pension plan. Eversource's expected long-term rates of return on Pension and PBOP Plan assets are based on target asset allocation assumptions and related expected long-term rates of return. In developing its expected long-term rate of return assumptions for the Pension and PBOP Plans, Eversource evaluated input from consultants, as well as long-term inflation assumptions and historical returns. For the year ended December 31, 2018, management has assumed long-term rates of return of 8.25 percent for the Eversource Service Pension and PBOP Plan assets. Management has assumed a 7 percent long-term rate of return for the Aquarion Plans.

These long-term rates of return are based on the assumed rates of return for the target asset allocations as follows:

	As of December 31,			
	2018		2017	
	Eversource Pension Plan and Tax-Exempt Assets Within PBOP Plan		Eversource Pension Plan and Tax-Exempt Assets Within PBOP Plan	
	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return
Equity Securities:				
United States	15.0%	8.5%	21.5%	8.5%
Global	10.0%	8.75%	—%	—%
Non-United States	8.0%	8.5%	11.0%	8.5%
Emerging Markets	4.0%	10.0%	4.5%	10.0%
Debt Securities:				
Fixed Income	13.0%	4.0%	11.0%	4.0%
Public High Yield Fixed Income	4.0%	6.5%	4.0%	6.5%
Private Debt	15.0%	9.0%	15.0%	9.0%
Emerging Markets Debt	—%	—%	2.0%	6.5%
Private Equity	15.0%	12.0%	15.0%	12.0%
Real Assets	16.0%	7.5%	12.0%	7.5%
Hedge Funds	—%	—%	4.0%	6.0%

The taxable assets within the Eversource PBOP Plan have a target asset allocation of 70 percent equity securities and 30 percent fixed income securities. The target asset allocation for the Aquarion Pension Plans is 59 percent equity, 36 percent debt and 5 percent other. The target asset allocation for the Aquarion PBOP Plan is 59 percent equity and 41 percent debt.

The following table presents, by asset category, the Pension and PBOP Plan assets recorded at fair value on a recurring basis by the level in which they are classified within the fair value hierarchy:

	Pension Plan							
	Fair Value Measurements as of December 31,							
(Millions of Dollars)	2018				2017			
Asset Category:	Level 1	Level 2	Uncategorized	Total	Level 1	Level 2	Uncategorized	Total
Equity Securities (1)	$ 443.4	$ —	$ 1,377.8	$ 1,821.2	$ 535.4	$ —	$ 1,653.3	$ 2,188.7
Fixed Income (2)	85.5	160.8	1,265.5	1,511.8	56.6	215.9	1,218.3	1,490.8
Private Equity	6.1	—	834.0	840.1	11.2	—	641.8	653.0
Real Assets (3)	62.9	—	569.1	632.0	101.6	—	539.9	641.5
Total	$ 597.9	$ 160.8	$ 4,046.4	$ 4,805.1	$ 704.8	$ 215.9	$ 4,053.3	$ 4,974.0
Less: 401(h) PBOP Assets (4)				(231.2)				(234.5)
Total Pension Assets				$ 4,573.9				$ 4,739.5

	PBOP Plan							
	Fair Value Measurements as of December 31,							
(Millions of Dollars)	2018				2017			
Asset Category:	**Level 1**	**Level 2**	**Uncategorized**	**Total**	**Level 1**	**Level 2**	**Uncategorized**	**Total**
Equity Securities (1)	$ 91.9	$ —	$ 210.5	$ 302.4	$ 115.3	$ —	$ 241.9	$ 357.2
Fixed Income (2)	22.0	40.3	123.0	185.3	23.4	44.0	133.9	201.3
Private Equity	—	—	32.7	32.7	—	—	31.3	31.3
Real Assets (3)	27.5	—	70.5	98.0	22.4	—	75.5	97.9
Total	$ 141.4	$ 40.3	$ 436.7	$ 618.4	$ 161.1	$ 44.0	$ 482.6	$ 687.7
Add: 401(h) PBOP Assets (4)				231.2				234.5
Total PBOP Assets				$ 849.6				$ 922.2

(1) United States, Global, Non-United States and Emerging Markets equity securities that are uncategorized include investments in commingled funds and hedge funds that are overlayed with equity index swaps and futures contracts.

(2) Fixed Income investments that are uncategorized include investments in commingled funds, fixed income funds that invest in a variety of opportunistic and fixed income strategies, and hedge funds that are overlayed with fixed income futures.

(3) Real assets include real estate funds and hedge funds.

(4) The assets of the Pension Plan include a 401(h) account that has been allocated to provide health and welfare postretirement benefits under the PBOP Plan.

The Company values assets based on observable inputs when available. Equity securities, exchange traded funds and futures contracts classified as Level 1 in the fair value hierarchy are priced based on the closing price on the primary exchange as of the balance sheet date.

Fixed income securities, such as government issued securities, corporate bonds and high yield bond funds, are included in Level 2 and are valued using pricing models, quoted prices of securities with similar characteristics or discounted cash flows. The pricing models utilize observable inputs such as recent trades for the same or similar instruments, yield curves, discount margins and bond structures. Swaps are valued using pricing models that incorporate interest rates and equity and fixed income index closing prices to determine a net present value of the cash flows.

Certain investments, such as commingled funds, private equity investments, real estate funds and hedge funds are valued using the NAV as a practical expedient. These investments are structured as investment companies offering shares or units to multiple investors for the purpose of providing a return. Commingled funds are recorded at NAV provided by the asset manager, which is based on the market prices of the underlying equity securities. Private Equity investments, Fixed Income partnership funds and Real Assets are valued using the NAV provided by the partnerships, which are based on discounted cash flows of the underlying investments, real estate appraisals or public market comparables of the underlying investments, or the NAV of underlying assets held in hedge funds. Assets valued at NAV are uncategorized in the fair value hierarchy.

B. Defined Contribution Plans

Eversource maintains defined contribution plans on behalf of eligible participants. The Eversource 401k Plan provides for employee and employer contributions up to statutory limits. For eligible employees, the Eversource 401k Plan provides employer matching contributions of either 100 percent up to a maximum of three percent of eligible compensation or 50 percent up to a maximum of eight percent of eligible compensation. The Eversource 401k Plan also contains a K-Vantage feature for the benefit of eligible participants, which provides an additional annual employer contribution based on age and years of service. K-Vantage participants are not eligible to actively participate in the Eversource Pension Plan.

The total Eversource 401k Plan employer matching contributions, including the K-Vantage contributions, were as follows:

(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
2018	$ 38.4	$ 5.0	$ 9.7	$ 3.3
2017	34.5	4.6	8.5	3.7
2016	31.8	4.5	8.1	3.4

C. Share-Based Payments

Share-based compensation awards are recorded using a fair-value based method at the date of grant. Eversource, CL&P, NSTAR Electric and PSNH record compensation expense related to these awards, as applicable, for shares issued or sold to their respective employees and officers, as well as for the allocation of costs associated with shares issued or sold to Eversource's service company employees and officers that support CL&P, NSTAR Electric and PSNH.

Eversource Incentive Plans: Eversource maintains long-term equity-based incentive plans in which Eversource, CL&P, NSTAR Electric and PSNH employees, officers and board members are eligible to participate. The incentive plans authorize Eversource to grant up to 6,700,000 new shares for various types of awards, including RSUs and performance shares, to eligible employees, officers, and board members. As of December 31, 2018 and 2017, Eversource had 3,720,650 and 2,445,110 common shares, respectively, available for issuance under these plans.

Eversource accounts for its various share-based plans as follows:

- RSUs - Eversource records compensation expense, net of estimated forfeitures, on a straight-line basis over the requisite service period based upon the fair value of Eversource's common shares at the date of grant. The par value of RSUs is reclassified to Common Stock from APIC as RSUs become issued as common shares.

- Performance Shares - Eversource records compensation expense, net of estimated forfeitures, on a straight-line basis over the requisite service period. Performance shares vest based upon the extent to which Company goals are achieved. Vesting of outstanding performance shares is based upon both the Company's EPS growth over the requisite service period and the total shareholder return as compared to the Edison Electric Institute ("EEI") Index during the requisite service period. The fair value of performance shares is determined at the date of grant using a lattice model.

RSUs: Eversource granted RSUs under the annual long-term incentive programs that are subject to three-year graded vesting schedules for employees, and one-year graded vesting schedules, or immediate vesting, for board members. RSUs are paid in shares, reduced by amounts sufficient to satisfy withholdings for income taxes, subsequent to vesting. A summary of RSU transactions is as follows:

	RSUs (Units)	Weighted Average Grant-Date Fair Value
Outstanding as of December 31, 2017	717,039	$ 49.29
Granted	286,315	$ 56.69
Shares Issued	(201,386)	$ 55.35
Forfeited	(19,603)	$ 56.78
Outstanding as of December 31, 2018	782,365	$ 50.25

The weighted average grant-date fair value of RSUs granted for the years ended December 31, 2018, 2017 and 2016 was $56.69, $55.97 and $54.67, respectively. As of December 31, 2018 and 2017, the number and weighted average grant-date fair value of unvested RSUs was 424,119 and $56.57 per share, and 388,269 and $56.15 per share, respectively. During 2018, there were 216,572 RSUs at a weighted average grant-date fair value of $56.72 per share that vested during the year and were either paid or deferred. As of December 31, 2018, 358,246 RSUs were fully vested and deferred and an additional 402,913 are expected to vest.

Performance Shares: Eversource granted performance shares under the annual long-term incentive programs that vest based upon the extent to which Company goals are achieved at the end of three-year performance measurement periods. Performance shares are paid in shares, after the performance measurement period. A summary of performance share transactions is as follows:

	Performance Shares (Units)	Weighted Average Grant-Date Fair Value
Outstanding as of December 31, 2017	510,565	$ 55.45
Granted	184,355	$ 56.77
Shares Issued	(178,258)	$ 54.98
Forfeited	(17,098)	$ 56.18
Outstanding as of December 31, 2018	499,564	$ 56.08

The weighted average grant-date fair value of performance shares granted for the years ended December 31, 2018, 2017 and 2016 was $56.77, $55.70 and $53.64, respectively. As of December 31, 2018 and 2017, the number and weighted average grant-date fair value of unvested performance shares was 366,995 and $56.17 per share, and 331,207 and $55.79 per share, respectively. During 2018, there were 131,349 performance shares at a weighted average grant-date fair value of $56.08 per share that vested during the year and were either paid or deferred. As of December 31, 2018, 132,569 performance shares were fully vested and deferred.

Compensation Expense: The total compensation expense and associated future income tax benefits recognized by Eversource, CL&P, NSTAR Electric and PSNH for share-based compensation awards were as follows:

Eversource	For the Years Ended December 31,		
(Millions of Dollars)	2018	2017	2016
Compensation Expense	$ 21.4	$ 19.7	$ 23.6
Future Income Tax Benefit	5.4	8.0	9.6

	For the Years Ended December 31,								
	2018			2017			2016		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Compensation Expense	$ 7.8	$ 7.7	$ 2.9	$ 7.0	$ 7.0	$ 3.2	$ 9.1	$ 8.2	$ 3.5
Future Income Tax Benefit	2.0	1.9	0.7	2.9	2.8	1.3	3.7	3.3	1.4

As of December 31, 2018, there was $22.3 million of total unrecognized compensation expense related to nonvested share-based awards for Eversource, including $8.1 million for CL&P, $8.0 million for NSTAR Electric and $2.8 million for PSNH. This cost is expected to be recognized ratably over a weighted-average period of 1.73 years for Eversource and CL&P, and 1.72 years for NSTAR Electric and PSNH.

An income tax rate of 25 percent was used to estimate the tax effect on total share-based payments determined under the fair-value based method for all awards. During both 2018 and 2017, the Company generally settled fully vested RSUs and performance shares with the issuance of common shares purchased in the open market.

For the years ended December 31, 2018, 2017 and 2016, excess tax benefits associated with the distribution of stock compensation awards reduced income tax expense by $1.5 million, $2.9 million, and $19.1 million, respectively, which increased cash flows from operating activities on the statements of cash flows.

D. Other Retirement Benefits

Eversource provides retirement and other benefits for certain current and past company officers. These benefits are accounted for on an accrual basis and expensed over a period equal to the service lives of the employees. The actuarially-determined liability for these benefits, which is included in Other Long-Term Liabilities on the balance sheets, as well as the related expense included in Operations and Maintenance Expense on the income statements, are as follows:

Eversource *(Millions of Dollars)*	**As of and For the Years Ended December 31,**		
	2018	**2017**	**2016**
Actuarially-Determined Liability	$ 49.1	$ 53.4	$ 54.2
Other Retirement Benefits Expense	2.7	2.8	2.9

	As of and For the Years Ended December 31,								
	2018			**2017**			**2016**		
(Millions of Dollars)	**CL&P**	**NSTAR Electric**	**PSNH**	**CL&P**	**NSTAR Electric**	**PSNH**	**CL&P**	**NSTAR Electric**	**PSNH**
Actuarially-Determined Liability	$ 0.3	$ 0.1	$ 1.7	$ 0.3	$ 0.1	$ 1.9	$ 0.3	$ 0.1	$ 2.0
Other Retirement Benefits Expense	1.1	1.1	0.4	1.0	1.0	0.5	1.1	0.9	0.6

11. INCOME TAXES

The components of income tax expense are as follows:

Eversource *(Millions of Dollars)*	**For the Years Ended December 31,**		
	2018	**2017**	**2016**
Current Income Taxes:			
Federal	$ 106.5	$ 58.9	$ 38.9
State	10.6	31.6	53.0
Total Current	117.1	90.5	91.9
Deferred Income Taxes, Net:			
Federal	122.6	433.0	427.9
State	52.2	58.6	38.6
Total Deferred	174.8	491.6	466.5
Investment Tax Credits, Net	(2.9)	(3.2)	(3.4)
Income Tax Expense	$ 289.0	$ 578.9	$ 555.0

	For the Years Ended December 31,								
	2018			2017			2016		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Current Income Taxes:									
Federal	$ 54.2	$ 79.3	$ 12.2	$ 50.9	$ 107.8	$ 18.6	$ 27.3	$ 86.4	$ (13.7)
State	20.9	30.0	(0.5)	17.4	25.6	6.2	13.3	39.5	8.8
Total Current	75.1	109.3	11.7	68.3	133.4	24.8	40.6	125.9	(4.9)
Deferred Income Taxes, Net:									
Federal	48.5	27.9	15.4	123.9	88.1	52.7	157.6	96.6	79.5
State	6.4	13.5	20.5	(4.6)	22.4	11.2	11.3	5.1	7.8
Total Deferred	54.9	41.4	35.9	119.3	110.5	63.9	168.9	101.7	87.3
Investment Tax Credits, Net	(0.9)	(1.8)	—	(1.0)	(1.8)	—	(1.2)	(1.8)	—
Income Tax Expense	$ 129.1	$ 148.9	$ 47.6	$ 186.6	$ 242.1	$ 88.7	$ 208.3	$ 225.8	$ 82.4

A reconciliation between income tax expense and the expected tax expense at the statutory rate is as follows:

Eversource *(Millions of Dollars, except percentages)*	For the Years Ended December 31,		
	2018	2017	2016
Income Before Income Tax Expense	$ 1,329.5	$ 1,574.4	$ 1,504.8
Statutory Federal Income Tax Expense at 21% in 2018 and 35% in 2017 and 2016	279.2	551.0	526.7
Tax Effect of Differences:			
Depreciation	(30.8)	(10.8)	(3.4)
Investment Tax Credit Amortization	(2.9)	(3.2)	(3.4)
Other Federal Tax Credits	—	—	(3.5)
State Income Taxes, Net of Federal Impact	44.4	47.7	56.2
Dividends on ESOP	(5.1)	(8.4)	(8.4)
Tax Asset Valuation Allowance/Reserve Adjustments	5.2	7.0	3.3
Excess Stock Benefit	(1.5)	(2.9)	(19.1)
Other, Net	0.5	(1.5)	6.6
Income Tax Expense	$ 289.0	$ 578.9	$ 555.0
Effective Tax Rate	21.7%	36.8%	36.9%

	For the Years Ended December 31,								
	2018			2017			2016		
(Millions of Dollars,except percentages)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Income Before Income Tax Expense	$ 506.8	$ 532.0	$ 163.5	$ 563.4	$ 616.8	$ 224.7	$ 542.6	$ 576.6	$ 214.3
Statutory Federal Income Tax Expense at 21% in 2018 and 35% in 2017 and 2016	106.4	111.7	34.3	197.2	215.9	78.6	189.9	201.8	75.0
Tax Effect of Differences:									
Depreciation	(1.2)	(2.8)	0.1	(5.2)	(3.0)	1.1	1.6	(3.1)	1.0
Investment Tax Credit Amortization	(0.9)	(1.8)	—	(1.0)	(1.8)	—	(1.2)	(1.8)	—
Other Federal Tax Credits	—	—	—	—	—	—	—	—	(3.5)
State Income Taxes, Net of Federal Impact	14.5	33.2	15.8	4.5	31.2	11.3	14.5	29.0	10.8
Tax Asset Valuation Allowance/Reserve Adjustments	7.1	1.2	—	(9.5)	—	—	1.5	—	—
Excess Stock Benefit	(0.1)	(0.1)	(0.1)	(0.7)	(0.7)	(0.3)	(0.9)	(1.2)	(0.4)
Other, Net	3.3	7.5	(2.5)	1.3	0.5	(2.0)	2.9	1.1	(0.5)
Income Tax Expense	$ 129.1	$ 148.9	$ 47.6	$ 186.6	$ 242.1	$ 88.7	$ 208.3	$ 225.8	$ 82.4
Effective Tax Rate	25.5%	28.0%	29.1%	33.1%	39.2%	39.5%	38.4%	39.2%	38.4%

Eversource, CL&P, NSTAR Electric and PSNH file a consolidated federal income tax return and unitary, combined and separate state income tax returns. These entities are also parties to a tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized.

Deferred tax assets and liabilities are recognized for the future tax effects of temporary differences between the carrying amounts and the tax basis of assets and liabilities. The tax effect of temporary differences is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions and relevant accounting authoritative literature. The tax effects of temporary differences that give rise to the net accumulated deferred income tax obligations are as follows:

	As of December 31,							
	2018				2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Deferred Tax Assets:								
Employee Benefits	$ 388.2	$ 94.5	$ 35.0	$ 31.1	$ 442.1	$ 112.3	$ 34.0	$ 38.0
Derivative Liabilities	111.4	111.4	—	—	111.8	110.5	0.3	—
Regulatory Deferrals - Liabilities	299.3	38.6	195.5	16.1	205.6	12.0	139.8	17.9
Allowance for Uncollectible Accounts	54.0	23.1	17.8	3.0	50.1	20.6	17.3	2.9
Tax Effect - Tax Regulatory Liabilities	830.3	336.8	288.9	111.7	832.6	337.2	281.2	116.8
Net Operating Loss Carryforwards	28.5	—	—	0.6	47.8	—	—	—
Purchase Accounting Adjustment	64.2	—	—	—	69.9	—	—	—
Other	166.2	81.1	15.6	33.4	149.5	70.7	4.9	49.6
Total Deferred Tax Assets	1,942.1	685.5	552.8	195.9	1,909.4	663.3	477.5	225.2
Less: Valuation Allowance	19.5	10.7	—	—	14.6	6.3	—	—
Net Deferred Tax Assets	$ 1,922.6	$ 674.8	$ 552.8	$ 195.9	$ 1,894.8	$ 657.0	$ 477.5	$ 225.2
Deferred Tax Liabilities:								
Accelerated Depreciation and Other Plant-Related Differences	$ 3,724.2	$ 1,293.3	$ 1,342.4	$ 410.6	$ 3,562.0	$ 1,224.9	$ 1,229.2	$ 502.5
Property Tax Accruals	73.2	35.4	26.3	5.2	56.7	20.7	24.2	5.5
Regulatory Amounts:								
Regulatory Deferrals - Assets	1,025.9	320.1	277.4	213.8	924.9	310.6	267.1	103.6
Tax Effect - Tax Regulatory Assets	238.9	167.0	9.7	8.1	243.1	173.1	9.8	11.4
Goodwill Regulatory Asset - 1999 Merger	95.2	—	81.7	—	99.8	—	85.7	—
Derivative Assets	20.1	19.9	—	—	17.4	17.4	—	—
Other	251.1	5.9	109.8	39.4	288.4	13.7	137.3	45.7
Total Deferred Tax Liabilities	$ 5,428.6	$ 1,841.6	$ 1,847.3	$ 677.1	$ 5,192.3	$ 1,760.4	$ 1,753.3	$ 668.7

2017 Federal Legislation: On December 22, 2017, the Tax Cuts and Jobs Act became law, which amended existing federal tax rules and included numerous provisions that impacted corporations. In particular, the act reduced the U.S. federal corporate income tax rate from 35 percent to 21 percent effective January 1, 2018. For our regulated companies, the most significant changes are (1) the benefit of incurring a lower federal income tax expense and (2) the reduction in ADIT liabilities (now excess ADIT or EDIT), which were estimated to be approximately $2.9 billion and included in regulatory liabilities as of December 31, 2018. In 2018, Eversource refunded $5.0 million ($4.4 million at PSNH and $0.6 million at Yankee Gas) to customers. See Note 2, "Regulatory Accounting," to the financial statements for further information.

The Company assessed the applicable provisions in the act and recorded the associated impacts as of December 31, 2017. The Company recorded the provisional income tax amounts as of December 31, 2017 in accordance with SEC Staff Accounting Bulletin No. 118 ("SAB 118") issued by the SEC in December 2017, for changes pursuant to the act because the impacts could not be finalized upon issuance of the financial statements, but for which reasonable estimates could be determined. The Company has completed its evaluation of the impacts of the act as of December 31, 2018. The

ultimate outcome was not materially different from the provisional estimates recorded as of December 31, 2017. While the Company has recorded the impacts of the act based on interpretation of the provisions as enacted, it is expected the U.S. Department of Treasury and the IRS will issue additional interpretative guidance in the future that could result in changes to previously finalized provisions. At this time, some of the states in which the Company does business have issued guidance regarding the act and the impact was not material.

Carryforwards: The following tables provide the amounts and expiration dates of state tax credit and loss carryforwards and federal tax credit and net operating loss carryforwards:

	As of December 31,									
	2018					2017				
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Expiration Range	Eversource	CL&P	NSTAR Electric	PSNH	Expiration Range
Federal Net Operating Loss	$ 103.6	$ —	$ —	$ —	2033 - 2037	$ 197.3	$ —	$ —	$ —	2027 - 2037
Federal Charitable Contribution	2.2	—	—	—	2020 - 2022	18.7	—	—	—	2017 - 2022
State Net Operating Loss	80.7	—	—	—	2019 - 2038	82.8	—	—	—	2028 - 2037
State Tax Credit	148.9	107.0	—	—	2018 - 2023	139.0	94.5	—	—	2017 - 2022
State Charitable Contribution	9.6	—	—	—	2019 - 2023	31.4	—	—	—	2017 - 2022

In 2018, the company increased its valuation allowance reserve for state credits by $5.2 million ($4.4 million for CL&P), net of tax, to reflect an update for expired tax credits. In 2017, the Company increased its valuation allowance reserve for state credits by $9.9 million ($1.8 million for CL&P), net of tax, to reflect an update for expired tax credits.

For 2018 and 2017, state credit and state loss carryforwards have been partially reserved by a valuation allowance of $19.5 million and $14.4 million (net of tax), respectively.

Unrecognized Tax Benefits: A reconciliation of the activity in unrecognized tax benefits, all of which would impact the effective tax rate if recognized, is as follows:

(Millions of Dollars)	Eversource	CL&P
Balance as of January 1, 2016	$ 48.0	$ 13.5
Gross Increases - Current Year	9.9	3.9
Gross Increases - Prior Year	0.2	0.2
Lapse of Statute of Limitations	(9.7)	(2.3)
Balance as of December 31, 2016	48.4	15.3
Gross Increases - Current Year	11.4	4.7
Gross Decreases - Prior Year	(0.9)	(0.5)
Lapse of Statute of Limitations	(7.2)	(1.4)
Balance as of December 31, 2017	51.7	18.1
Gross Increases - Current Year	9.2	3.2
Gross Decreases - Prior Year	(6.5)	(0.9)
Lapse of Statute of Limitations	(8.5)	(2.2)
Balance as of December 31, 2018	$ 45.9	$ 18.2

Interest and Penalties: Interest on uncertain tax positions is recorded and generally classified as a component of Other Interest Expense on the statements of income. However, when resolution of uncertainties results in the Company receiving interest income, any related interest benefit is recorded in Other Income, Net on the statements of income. No penalties have been recorded. The amount of interest expense/(income) on uncertain tax positions recognized and the related accrued interest payable/(receivable) are as follows:

	Other Interest Expense/(Income)			Accrued Interest Expense	
	For the Years Ended December 31,			As of December 31,	
(Millions of Dollars)	2018	2017	2016	2018	2017
Eversource	$ (1.7)	$ —	$ (0.2)	$ 0.1	$ 1.8

Tax Positions: During 2018 and 2017, Eversource did not resolve any of its uncertain tax positions.

Open Tax Years: The following table summarizes Eversource, CL&P, NSTAR Electric and PSNH's tax years that remain subject to examination by major tax jurisdictions as of December 31, 2018:

Description	Tax Years
Federal	2018
Connecticut	2015 - 2018
Massachusetts	2015 - 2018
New Hampshire	2016 - 2018

Eversource does not estimate to have an earnings impact related to unrecognized tax benefits during the next twelve months.

12. COMMITMENTS AND CONTINGENCIES

A. Environmental Matters

General: Eversource, CL&P, NSTAR Electric and PSNH are subject to environmental laws and regulations intended to mitigate or remove the effect of past operations and improve or maintain the quality of the environment. These laws and regulations require the removal or the remedy of the effect on the environment of the disposal or release of certain specified hazardous substances at current and former operating sites. Eversource, CL&P, NSTAR Electric and PSNH have an active environmental auditing and training program and each believes it is substantially in compliance with all enacted laws and regulations.

Environmental reserves are accrued when assessments indicate it is probable that a liability has been incurred and an amount can be reasonably estimated. The approach used estimates the liability based on the most likely action plan from a variety of available remediation options, including no action required or several different remedies ranging from establishing institutional controls to full site remediation and monitoring. These liabilities are estimated on an undiscounted basis and do not assume that the amounts are recoverable from insurance companies or other third parties. The environmental reserves include sites at different stages of discovery and remediation and do not include any unasserted claims.

These reserve estimates are subjective in nature as they take into consideration several different remediation options at each specific site. The reliability and precision of these estimates can be affected by several factors, including new information concerning either the level of contamination at the site, the extent of Eversource's, CL&P's, NSTAR Electric's and PSNH's responsibility for remediation or the extent of remediation required, recently enacted laws and regulations or changes in cost estimates due to certain economic factors. It is possible that new information or future developments could require a reassessment of the potential exposure to required environmental remediation. As this information becomes available, management will continue to assess the potential exposure and adjust the reserves accordingly.

The amounts recorded as environmental reserves are included in Other Current Liabilities and Other Long-Term Liabilities on the balance sheets and represent management's best estimate of the liability for environmental costs, and take into consideration site assessment, remediation and long-term monitoring costs. The environmental reserves also take into account recurring costs of managing hazardous substances and pollutants, mandated expenditures to remediate contaminated sites and any other infrequent and non-recurring clean-up costs. A reconciliation of the activity in the environmental reserves is as follows:

(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
Balance as of January 1, 2017	$ 65.8	$ 4.9	$ 3.8	$ 5.3
Additions	6.2	0.5	1.8	1.0
Payments/Reductions	(17.1)	(0.7)	(2.9)	(0.6)
Balance as of December 31, 2017	54.9	4.7	2.7	5.7
Additions	23.5	1.9	9.7	—
Payments/Reductions	(13.7)	(1.2)	(1.5)	(0.3)
Balance as of December 31, 2018	$ 64.7	$ 5.4	$ 10.9	$ 5.4

The number of environmental sites for which remediation or long-term monitoring, preliminary site work or site assessment is being performed are as follows:

	Eversource	CL&P	NSTAR Electric	PSNH
2018	60	15	16	9
2017	59	14	15	10

The increase in the reserve balance was due primarily to the addition of environmental sites at NSTAR Electric and changes in cost estimates at certain MGP sites at our natural gas companies under investigation for which additional remediation will be required.

Included in the Eversource number of sites and reserve amounts above are former MGP sites that were operated several decades ago and manufactured gas from coal and other processes, which resulted in certain by-products remaining in the environment that may pose a potential risk to human health and the environment, for which Eversource may have potential liability. The reserve balances related to these former MGP sites were $50.1 million and $49.0 million as of December 31, 2018 and 2017, respectively, and related primarily to the natural gas business segment.

As of December 31, 2018, for 7 environmental sites (2 for CL&P) that are included in the Company's reserve for environmental costs, the information known and the nature of the remediation options allow for the Company to estimate the range of losses for environmental costs. As of December 31, 2018, $23.8 million (including $0.7 million for CL&P) had been accrued as a liability for these sites, which represents the low end of the range of the liabilities for environmental costs. Management believes that additional losses of up to approximately $20 million ($1 million at CL&P) may be incurred in executing current remediation plans for these sites.

As of December 31, 2018, for 12 environmental sites (4 for CL&P and 3 for NSTAR Electric) that are included in the Company's reserve for environmental costs, management cannot reasonably estimate the exposure to loss in excess of the reserve, or range of loss, as these sites are under investigation and/or there is significant uncertainty as to what remedial actions, if any, the Company may be required to undertake. As of December 31, 2018, $11.1 million (including $1.9 million for CL&P and $1.9 million for NSTAR Electric) had been accrued as a liability for these sites. As of December 31, 2018, for the remaining 41 environmental sites (including 9 for CL&P, 13 for NSTAR Electric and 9 for PSNH) that are included in the Company's reserve for environmental costs, the $29.8 million accrual (including $2.8 million for CL&P, $9.0 million for NSTAR Electric and $5.4 million for PSNH) represents management's best estimate of the probable liability and no additional loss is anticipated at this time.

Environmental Rate Recovery: PSNH, NSTAR Gas and Yankee Gas have rate recovery mechanisms for MGP related environmental costs, therefore, changes in their respective environmental reserves do not impact Net Income. Effective with the May 2018 distribution rate case settlement, CL&P is allowed to defer certain environmental costs for future recovery. NSTAR Electric does not have a separate environmental cost recovery regulatory

mechanism.

B. Long-Term Contractual Arrangements

Estimated Future Annual Costs: The estimated future annual costs of significant executed, non-cancelable, long-term contractual arrangements in effect as of December 31, 2018 are as follows:

Eversource

(Millions of Dollars)	2019	2020	2021	2022	2023	Thereafter	Total
Purchased Power and Capacity	$ 68.3	$ 73.5	$ 69.1	$ 72.9	$ 74.1	$ 142.9	$ 500.8
Renewable Energy	262.4	261.0	238.9	240.5	217.2	1,662.0	2,882.0
Peaker CfDs	11.9	22.6	21.9	15.3	17.5	43.5	132.7
Natural Gas Procurement	243.8	227.7	183.6	149.2	135.1	1,039.7	1,979.1
Transmission Support Commitments	22.8	23.1	15.2	16.2	17.8	17.8	112.9
Total	$ 609.2	$ 607.9	$ 528.7	$ 494.1	$ 461.7	$ 2,905.9	$ 5,607.5

CL&P

(Millions of Dollars)	2019	2020	2021	2022	2023	Thereafter	Total
Purchased Power and Capacity	$ 57.0	$ 69.7	$ 65.3	$ 69.1	$ 70.4	$ 123.9	$ 455.4
Renewable Energy	102.0	103.8	104.0	104.9	105.5	785.3	1,305.5
Peaker CfDs	11.9	22.6	21.9	15.3	17.5	43.5	132.7
Transmission Support Commitments	9.0	9.1	6.0	6.4	7.0	7.0	44.5
Total	$ 179.9	$ 205.2	$ 197.2	$ 195.7	$ 200.4	$ 959.7	$ 1,938.1

NSTAR Electric

(Millions of Dollars)	2019	2020	2021	2022	2023	Thereafter	Total
Purchased Power and Capacity	$ 5.5	$ 3.1	$ 3.1	$ 3.1	$ 3.0	$ 19.0	$ 36.8
Renewable Energy	94.7	93.1	88.6	88.8	63.9	435.1	864.2
Transmission Support Commitments	9.0	9.1	6.0	6.3	7.0	7.0	44.4
Total	$ 109.2	$ 105.3	$ 97.7	$ 98.2	$ 73.9	$ 461.1	$ 945.4

PSNH

(Millions of Dollars)	2019	2020	2021	2022	2023	Thereafter	Total
Purchased Power and Capacity	$ 5.8	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ —	$ 8.6
Renewable Energy	65.7	64.1	46.3	46.8	47.8	441.6	712.3
Transmission Support Commitments	4.8	4.9	3.2	3.5	3.8	3.8	24.0
Total	$ 76.3	$ 69.7	$ 50.2	$ 51.0	$ 52.3	$ 445.4	$ 744.9

Purchased Power and Capacity: CL&P, NSTAR Electric and PSNH have various IPP contracts or purchase obligations for electricity. Such contracts extend through 2024 for CL&P, 2031 for NSTAR Electric and 2023 for PSNH.

In addition, CL&P, along with UI, has four capacity CfDs for a total of approximately 787 MW of capacity consisting of three generation units and one demand response project. The capacity CfDs extend through 2026 and obligate both CL&P and UI to make or receive payments on a monthly basis to or from the generation facilities based on the difference between a set contractual capacity price and the capacity market prices received by the generation facilities in the ISO-NE capacity markets. CL&P has a sharing agreement with UI, whereby UI shares 20 percent of the costs and

benefits of these contracts. CL&P's portion of the costs and benefits of these contracts will be paid by, or refunded to, CL&P's customers.

The contractual obligations table above does not include CL&P's, NSTAR Electric's or PSNH's standard/basic service contracts, the amounts of which vary with customers' energy needs.

Renewable Energy: Renewable energy contracts include non-cancellable commitments under contracts of CL&P, NSTAR Electric and PSNH for the purchase of energy and capacity from renewable energy facilities. Such contracts extend through 2039 for CL&P, 2038 for NSTAR Electric and 2033 for PSNH.

The contractual obligations table above does not include long-term commitments signed by CL&P and NSTAR Electric, as required by the PURA and DPU, respectively, for the purchase of renewable energy and related products that are contingent on the future construction of energy facilities. The table also excludes certain CL&P long-term commitments required by regulation that have not yet been executed such as the selection of certain nuclear power-generating facilities awarded under the Act Concerning Zero Carbon Solicitation and Procurement.

Peaker CfDs: In 2008, CL&P entered into three CfDs with developers of peaking generation units approved by PURA (Peaker CfDs). These units have a total of approximately 500 MW of peaking capacity. As directed by PURA, CL&P and UI have entered into a sharing agreement, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of these CfDs. The Peaker CfDs pay the generation facility owner the difference between capacity, forward reserve and energy market revenues and a cost-of-service payment stream for 30 years. The ultimate cost or benefit to CL&P under these contracts will depend on the costs of plant operation and the prices that the projects receive for capacity and other products in the ISO-NE markets. CL&P's portion of the amounts paid or received under the Peaker CfDs will be recoverable from, or refunded to, CL&P's customers.

Natural Gas Procurement: In the normal course of business, Eversource's natural gas distribution businesses have long-term contracts for the purchase, transportation and storage of natural gas as part of its portfolio of supplies. These contracts extend through 2034.

Transmission Support Commitments: Along with other New England utilities, CL&P, NSTAR Electric and PSNH entered into agreements in 1985 to support transmission and terminal facilities that were built to import electricity from the Hydro-Québec system in Canada. CL&P, NSTAR Electric and PSNH are obligated to pay, over a 30-year period ending in 2020, their proportionate shares of the annual operation and maintenance expenses and capital costs of those facilities.

The total costs incurred under these agreements were as follows:

Eversource	**For the Years Ended December 31,**		
(Millions of Dollars)	**2018**	**2017**	**2016**
Purchased Power and Capacity	$ 72.0	$ 103.9	$ 152.5
Renewable Energy	218.5	235.5	210.9
Peaker CfDs	20.9	38.7	47.7
Natural Gas Procurement	432.4	377.0	323.9
Transmission Support Commitments	23.4	19.8	15.9
Coal, Wood and Other (1)	—	47.7	55.7

	For the Years Ended December 31,								
	2018			2017			2016		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Purchased Power and Capacity	$ 49.4	$ 4.4	$ 18.2	$ 81.0	$ 4.0	$ 18.9	$ 132.7	$ 0.7	$ 19.1
Renewable Energy	63.2	89.8	65.5	51.0	123.7	60.8	42.1	101.1	67.7
Peaker CfDs	20.9	—	—	38.7	—	—	47.7	—	—
Transmission Support Commitments	9.2	9.2	5.0	7.8	7.8	4.2	6.3	6.2	3.4
Coal, Wood and Other (1)	—	—	—	—	—	47.7	—	—	55.7

(1) PSNH previously entered into various arrangements for the purchase of coal, wood and the transportation services for fuel supply for its electric generating assets. On January 10, 2018, Eversource and PSNH completed the sale of PSNH's thermal generation assets. On August 26, 2018, Eversource and PSNH completed the sale of PSNH's hydroelectric generation assets. Upon sale, the remaining future contractual obligations were transferred to the respective buyers. See Note 13, "Generation Asset Sale," for further information.

C. Spent Nuclear Fuel Obligations - Yankee Companies

CL&P, NSTAR Electric and PSNH have plant closure and fuel storage cost obligations to the Yankee Companies, which have each completed the physical decommissioning of their respective nuclear facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies have collected these costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including CL&P, NSTAR Electric and PSNH. These companies in turn recover these costs from their customers through state regulatory commission-approved retail rates. The Yankee Companies have collected amounts that management believes are adequate to recover the remaining plant closure and fuel storage cost estimates for the respective plants. Management believes CL&P and NSTAR Electric will recover their shares of these obligations from their customers. PSNH has recovered its total share of these costs from its customers.

Spent Nuclear Fuel Litigation:

The Yankee Companies have filed complaints against the DOE in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to provide for a permanent facility to store spent nuclear fuel pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE. The court had previously awarded the Yankee Companies damages for Phase I, II and III of litigation resulting from the DOE's failure to meet its contractual obligations. These Phases covered damages incurred in the years 1998 through 2012, and the awarded damages have been received by the Yankee Companies with certain amounts of the damages refunded to their customers.

DOE Phase III Damages - In August 2013, the Yankee Companies each filed subsequent lawsuits against the DOE seeking recovery of actual damages incurred in the years 2009 through 2012 ("DOE Phase III"). On March 25, 2016, the court issued its decision and awarded CYAPC, YAEC and MYAPC damages of $32.6 million, $19.6 million and $24.6 million, respectively. The decision became final on July 18, 2016, and the Yankee Companies received the awards from the DOE on October 14, 2016. The Yankee Companies received FERC approval of their proposed distribution of certain amounts of the awarded damages proceeds to member companies, including CL&P, NSTAR Electric and PSNH, which CYAPC and MYAPC made in December 2016. MYAPC also refunded $56.5 million from its spent nuclear fuel trust, a portion of which was also refunded to the Eversource utility subsidiaries. In total, Eversource received $26.1 million, of which CL&P, NSTAR Electric and PSNH received $13.6 million, $8.6 million and $3.9 million, respectively. These amounts have been refunded to the customers of the respective Eversource utility subsidiaries.

DOE Phase IV Damages - On May 22, 2017, each of the Yankee Companies filed subsequent lawsuits against the DOE in the Court of Federal Claims seeking monetary damages totaling approximately $100 million for CYAPC, YAEC and MYAPC, resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal covering the years from 2013 to 2016 (“DOE Phase IV”). On February 21, 2019, the Yankee Companies received a partial summary judgment and partial final judgment in their favor for the undisputed amount of monetary damages, which is the vast majority of the damages being sought. The DOE Phase IV trial for the remaining amount of damages is expected to begin in 2019.

D. Guarantees and Indemnifications

In the normal course of business, Eversource parent provides credit assurances on behalf of its subsidiaries, including CL&P, NSTAR Electric and PSNH, in the form of guarantees.

Eversource parent issued a guaranty on behalf of its subsidiary, NPT, under which, beginning at the time the Northern Pass Transmission line goes into commercial operation, Eversource parent will guarantee the financial obligations of NPT under the TSA with HQ in an amount not to exceed $25 million. Eversource parent's obligations under the guaranty expire upon the full, final and indefeasible payment of the guaranteed obligations. Eversource parent has also entered into a guaranty on behalf of NPT under which Eversource parent will guarantee NPT's obligations under a facility with a financial institution pursuant to which NPT may request letters of credit in an aggregate amount of up to approximately $14 million.

Management does not anticipate a material impact to net income or cash flows as a result of these various guarantees and indemnifications. The following table summarizes Eversource parent's exposure to guarantees and indemnifications of its subsidiaries to external parties, as of December 31, 2018:

Company	Description	Maximum Exposure (in millions)	Expiration Dates
On behalf of subsidiaries:			
Eversource Gas Transmission LLC	Access Northeast Project Capital Contributions Guaranty (1)	$ 184.9	2021
Various	Surety Bonds (2)	41.9	2019 - 2021
Rocky River Realty Company and Eversource Service	Lease Payments for Real Estate	6.3	2019 - 2024
Bay State Wind LLC	Real Estate Purchase	2.5	2019

(1) Eversource parent issued a declining balance guaranty on behalf of its subsidiary, Eversource Gas Transmission LLC, to guarantee the payment of the subsidiary's authorized capital contributions for its investment in the Access Northeast project. The guaranty decreases as authorized capital contributions are made. The guaranty will expire upon the earlier of the full performance of the guaranteed obligations or December 31, 2021.

(2) Surety bond expiration dates reflect termination dates, the majority of which will be renewed or extended. Certain surety bonds contain credit ratings triggers that would require Eversource parent to post collateral in the event that the unsecured debt credit ratings of Eversource parent are downgraded.

As described in Note 1K, "Investments," Eversource parent issued a guaranty on behalf of its subsidiary, Eversource Investment LLC. Eversource parent will guarantee, as a primary obligor, the financial obligations, primarily all post-Closing payment obligations of Eversource Investment LLC, under the Sale and Purchase Agreement and an Irrevocable Equity Commitment Letter with Ørsted in an amount not to exceed $127.6 million. Eversource parent's obligations under the guaranty expire upon the full, final and indefeasible payment of the guaranteed obligations.

E. FERC ROE Complaints

Four separate complaints have been filed at the FERC by combinations of New England state attorneys general, state regulatory commissions, consumer advocates, consumer groups, municipal parties and other parties (collectively the "Complainants"). In each of the first three complaints, filed on October 1, 2011, December 27, 2012, and July 31, 2014, respectively, the Complainants challenged the NETOs' base ROE of 11.14 percent that had been utilized since 2005 and sought an order to reduce it prospectively from the date of the final FERC order and for the separate 15-month complaint periods. In the fourth complaint, filed April 29, 2016, the Complainants challenged the NETOs' base ROE billed of 10.57 percent and the maximum ROE for transmission incentive ("incentive cap") of 11.74 percent, asserting that these ROEs were unjust and unreasonable.

The ROE originally billed during the period October 1, 2011 (beginning of the first complaint period) through October 15, 2014 consisted of a base ROE of 11.14 percent and incentives up to 13.1 percent. On October 16, 2014, the FERC set the base ROE at 10.57 percent and the incentive cap at 11.74 percent for the first complaint period. This was also effective for all prospective billings to customers beginning October 16, 2014. This FERC order was vacated on April 14, 2017 by the U.S. Court of Appeals for the D.C. Circuit (the "Court").

All amounts associated with the first complaint period have been refunded, which totaled $38.9 million (pre-tax and excluding interest) at Eversource and reflected both the base ROE and incentive cap prescribed by the FERC order. The refund consisted of $22.4 million for CL&P, $13.7 million for NSTAR Electric and $2.8 million for PSNH.

Eversource has recorded a reserve of $39.1 million (pre-tax and excluding interest) for the second complaint period as of December 31, 2018. This reserve represents the difference between the billed rates during the second complaint period and a 10.57 percent base ROE and 11.74 percent incentive cap. The reserve consisted of $21.4 million for CL&P, $14.6 million for NSTAR Electric and $3.1 million for PSNH as of December 31, 2018.

On October 16, 2018, FERC issued an order on all four complaints describing how it intends to address the issues that were remanded by the Court. FERC proposed a new framework to determine (1) whether an existing ROE is unjust and unreasonable and, if so, (2) how to calculate a replacement ROE. The parties to these proceedings were directed to submit briefs on this new proposed framework and how they would apply the proposed framework in each of the four complaint proceedings. Initial briefs were filed by the NETOs, Complainants and FERC Trial Staff on January 11, 2019. The NETOs' brief was supportive of the overall ROE methodology determined in the October 16, 2018 order providing the FERC does not change the proposed methodology or alter its implementation in a manner that has a material impact on the results. Reply briefs will be filed on March 8, 2019.

The FERC order included illustrative calculations for the first complaint using FERC's proposed frameworks with financial data from that complaint. Those preliminary calculations indicated that for the first complaint period, for the NETOs that FERC concludes are of average financial risk, (1) a preliminary range of presumptively just and reasonable base ROEs is 9.60 percent to 10.99 percent; (2) the pre-existing base ROE of 11.14 percent is therefore unjust and unreasonable; (3) the preliminary just and reasonable base ROE is 10.41 percent; and (4) the preliminary incentive cap on total ROE is 13.08 percent.

If the results of these illustrative calculations were included in a final FERC order for each of the complaint periods, then a 10.41 percent base ROE and a 13.08 percent incentive cap would not have a significant impact on our financial statements for all of the complaint periods.

Although the order provided illustrative calculations, FERC stated that these calculations are merely preliminary. The FERC's preliminary calculations are not binding and do not represent what we believe to be the most likely outcome of a final FERC order, as changes to the methodology by FERC are possible as a result of the parties' arguments and calculations in the briefing process. Until FERC issues a final decision on each of these four complaints, there is significant uncertainty, and at this time, the Company cannot reasonably estimate a range of gain or loss for any of the four complaint proceedings. The October 16, 2018 FERC order or the January 11, 2019 briefs did not provide a reasonable basis for a change to the reserve or recognized ROEs for any of the complaint periods.

Eversource, CL&P, NSTAR Electric and PSNH currently record revenues at the 10.57 percent base ROE and incentive cap at 11.74 percent established in the October 16, 2014 FERC order.

The average impact of a 10 basis point change to the base ROE for each of the 15-month complaint periods would affect Eversource's after-tax earnings by approximately $3 million.

F. Eversource and NSTAR Electric Boston Harbor Civil Action

On July 15, 2016, the United States Attorney on behalf of the United States Army Corps of Engineers filed a civil action in the United States District Court for the District of Massachusetts under provisions of the Rivers and Harbors Act of 1899 and the Clean Water Act against NSTAR Electric, Harbor Electric Energy Company, a wholly-owned subsidiary of NSTAR Electric ("HEEC"), and the Massachusetts Water Resources Authority (together with NSTAR Electric and HEEC, the "Defendants"). The action alleged that the Defendants failed to comply with certain permitting

requirements related to the placement of the HEEC-owned electric distribution cable beneath Boston Harbor. The action sought an order to compel HEEC to comply with cable depth requirements in the United States Army Corps of Engineers' permit or alternatively to remove the electric distribution cable and cease unauthorized work in U.S. waterways. The action also sought civil penalties and other costs.

The parties reached a settlement pursuant to which HEEC agreed to install a new 115kV distribution cable across Boston Harbor to Deer Island, utilizing a different route, and remove portions of the existing cable. Upon the installation and completion of the new cable and the removal of the portions of the existing cable, all issues surrounding the current permit from the United States Army Corps of Engineers are expected to be resolved, and such litigation is expected to be dismissed with prejudice.

In 2017, as a result of the settlement, NSTAR Electric expensed $4.9 million (pre-tax) of previously incurred capitalized costs associated with engineering work performed on the existing cable that will no longer be used. In addition, NSTAR Electric agreed to provide a rate base credit of $17.5 million to the Massachusetts Water Resources Authority for the new cable. This negotiated credit resulted in the initial $17.5 million of construction costs on the new cable being expensed as incurred, all of which was fully expensed by the end of 2018. Construction of the new cable is underway and is expected to be completed in 2019.

G. Litigation and Legal Proceedings

Eversource, including CL&P, NSTAR Electric and PSNH, are involved in legal, tax and regulatory proceedings regarding matters arising in the ordinary course of business, which involve management's assessment to determine the probability of whether a loss will occur and, if probable, its best estimate of probable loss. The Company records and discloses losses when these losses are probable and reasonably estimable, and discloses matters when losses are probable but not estimable or when losses are reasonably possible. Legal costs related to the defense of loss contingencies are expensed as incurred.

13. GENERATION ASSET SALE

In June 2015, Eversource and PSNH entered into the 2015 Public Service Company of New Hampshire Restructuring and Rate Stabilization Agreement, pursuant to which PSNH agreed to divest its generation assets, subject to NHPUC approval. The NHPUC approved this agreement as well as the final divestiture plan and auction process in 2016. On October 11, 2017, PSNH entered into two Purchase and Sale Agreements with private investors, one to sell its thermal generation assets at a purchase price of $175 million, subject to adjustment, (the “Thermal Agreement”) and a second to sell its hydroelectric generation assets at a purchase price of $83 million, subject to adjustment (the “Hydro Agreement”). The NHPUC approved these agreements in late November 2017, at which time the Company classified these assets as held for sale.

On January 10, 2018, PSNH completed the sale of its thermal generation assets pursuant to the Thermal Agreement. In accordance with the Thermal Agreement, the original purchase price of $175 million was adjusted to reflect working capital adjustments, closing date adjustments and proration of taxes and fees prior to closing, totaling $40.9 million. In the second quarter of 2018, the purchase price was further adjusted by $17.3 million relating to the valuation of certain allowances. As a result of these adjustments, net proceeds from the sale of the thermal assets totaled $116.8 million.

On July 16, 2018, FERC issued its order approving the transfer of PSNH's six hydroelectric licenses to private investors. On August 26, 2018, PSNH completed the sale of its hydroelectric generation assets pursuant to the Hydro Agreement. In accordance with the Hydro Agreement, the original purchase price of $83 million was adjusted to reflect contractual adjustments totaling $5.8 million, resulting in net proceeds of $77.2 million. The difference between the carrying value of the hydroelectric generation assets and the sale proceeds resulted in a gain of $17.3 million. An estimated gain from the sale of these assets was included as an offset to the total remaining costs associated with the sale of generation assets that were securitized on May 8, 2018.

On May 8, 2018, PSNH Funding issued $635.7 million of securitized RRBs to finance PSNH's unrecovered remaining costs associated with the divestiture of its generation assets, which included the deferred costs resulting from the sale of the thermal generation assets. These RRBs are secured by a non-bypassable charge recoverable from PSNH customers. As of December 31, 2018, unamortized securitized stranded costs totaled $608.4 million and are included in Regulatory Assets on the Eversource and PSNH balance sheets. As of December 31, 2017, the deferred costs resulting from the thermal generation asset sale of $516.1 million represented the difference between the carrying value and the fair value less cost to

sell the thermal generation assets. For further information on the securitized RRB issuance, see Note 9, "Rate Reduction Bonds and Variable Interest Entities."

For the year ended December 31, 2018, pre-tax income associated with the hydroelectric assets prior to the sale on August 26, 2018 was $9.9 million. For the years ended December 31, 2017 and 2016, pre-tax income associated with PSNH's generation assets was $60.0 million, and $65.3 million, respectively.

As of December 31, 2018, all generation assets had been sold and as a result, no generation assets were classified as held for sale. As of December 31, 2017, PSNH's generation assets held for sale, which were included in current assets on the Eversource and PSNH balance sheets, and were part of the Electric Distribution reportable segment, were as follows:

(Millions of Dollars)	As of December 31, 2017
Thermal Gross Plant	$ 1,091.4
Hydroelectric Gross Plant	83.0
Accumulated Depreciation	(575.4)
Net Plant	599.0
Fuel and Inventory	87.7
Materials and Supplies	27.3
Emission Allowances	19.1
Other Assets	2.6
Deferred Costs from Thermal Generation Asset Sale	(516.1)
Total Generation Assets Held for Sale	$ 219.6

14. LEASES

Eversource, including CL&P, NSTAR Electric and PSNH, has entered into lease agreements, some of which are capital leases, for the use of land, office space, service centers, vehicles, information technology, and office equipment. In addition, CL&P, NSTAR Electric and PSNH incur costs associated with leases entered into by affiliated Eversource subsidiaries, including Eversource Service and Rocky River Realty Company, and are included below in their respective operating lease rental expenses and future minimum rental payments. These intercompany lease amounts are eliminated on an Eversource consolidated basis. The provisions of the Eversource, CL&P, NSTAR Electric and PSNH lease agreements generally contain renewal options. One lease agreement contains payments impacted by the consumer price index.

Operating lease rental payments charged to expense are as follows:

(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
2018	$ 10.8	$ 10.9	$ 11.8	$ 2.5
2017	10.5	11.7	11.3	3.3
2016	12.1	12.5	11.4	2.9

Future minimum rental payments, excluding executory costs, such as property taxes, state use taxes, insurance, and maintenance, under long-term non-cancelable leases, as of December 31, 2018 are as follows:

Operating Leases *(Millions of Dollars)*	**Eversource**	**CL&P**	**NSTAR Electric**	**PSNH**
2019	$ 11.5	$ 1.5	$ 7.2	$ 0.5
2020	9.8	1.4	6.0	0.4
2021	8.7	1.2	5.3	0.4
2022	7.2	1.1	4.4	0.4
2023	4.7	0.5	3.1	0.2
Thereafter	32.7	0.2	29.5	0.3
Future minimum lease payments	$ 74.6	$ 5.9	$ 55.5	$ 2.2

Capital Leases *(Millions of Dollars)*	**Eversource**	**CL&P**	**NSTAR Electric**	**PSNH**
2019	$ 3.4	$ 2.0	$ 0.5	$ 0.1
2020	3.4	2.0	0.5	0.1
2021	2.9	1.5	0.5	0.1
2022	1.5	—	0.6	0.1
2023	0.7	—	0.6	0.1
Thereafter	13.9	—	13.4	0.5
Future minimum lease payments	25.8	5.5	16.1	1.0
Less amount to arrive at present value	13.8	1.0	12.4	0.1
Present value of future minimum lease payments	$ 12.0	$ 4.5	$ 3.7	$ 0.9

CL&P and PSNH entered into certain contracts for the purchase of energy that qualify as leases. These contracts do not have minimum lease payments and therefore are not included in the tables above. However, such contracts and corresponding expense have been included in the contractual obligations tables in Note 12B, "Commitments and Contingencies - Long-Term Contractual Arrangements," to the financial statements.

15. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each of the following financial instruments:

Preferred Stock, Long-Term Debt and Rate Reduction Bonds: The fair value of CL&P's and NSTAR Electric's preferred stock is based upon pricing models that incorporate interest rates and other market factors, valuations or trades of similar securities and cash flow projections. The fair value of long-term debt and RRB debt securities is based upon pricing models that incorporate quoted market prices for those issues or similar issues adjusted for market conditions, credit ratings of the respective companies and treasury benchmark yields. The fair values provided in the table below are classified as Level 2 within the fair value hierarchy. Carrying amounts and estimated fair values are as follows:

	Eversource		CL&P		NSTAR Electric		PSNH	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
As of December 31, 2018:								
Preferred Stock Not Subject to Mandatory Redemption	$ 155.6	$ 156.8	$ 116.2	$ 113.8	$ 43.0	$ 43.0	$ —	$ —
Long-Term Debt	13,086.1	13,154.9	3,254.0	3,429.2	2,944.8	3,024.1	805.2	819.5
Rate Reduction Bonds	635.7	645.8	—	—	—	—	635.7	645.8
As of December 31, 2017:								
Preferred Stock Not Subject to Mandatory Redemption	$ 155.6	$ 160.8	$ 116.2	$ 116.5	$ 43.0	$ 44.3	$ —	$ —
Long-Term Debt	12,325.5	12,877.1	3,059.1	3,430.5	2,943.8	3,156.5	1,002.4	1,038.2

Derivative Instruments and Marketable Securities: Derivative instruments and investments in marketable securities are carried at fair value. For further information, see Note 4, "Derivative Instruments," and Note 5, "Marketable Securities," to the financial statements.

See Note 1I, "Summary of Significant Accounting Policies – Fair Value Measurements," for the fair value measurement policy and the fair value hierarchy.

16. ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

The changes in accumulated other comprehensive income/(loss) by component, net of tax, are as follows:

	For the Year Ended December 31, 2018				For the Year Ended December 31, 2017			
Eversource *(Millions of Dollars)*	Qualified Cash Flow Hedging Instruments	Unrealized Losses on Marketable Securities	Defined Benefit Plans	Total	Qualified Cash Flow Hedging Instruments	Unrealized Gains/(Losses) on Marketable Securities	Defined Benefit Plans	Total
Balance as of January 1st	$ (6.2)	$ —	$ (60.2)	$ (66.4)	$ (8.2)	$ 0.4	$ (57.5)	$ (65.3)
OCI Before Reclassifications	—	(0.5)	0.3	(0.2)	—	(0.4)	(7.2)	(7.6)
Amounts Reclassified from AOCI	1.8	—	4.8	6.6	2.0	—	4.5	6.5
Net OCI	1.8	(0.5)	5.1	6.4	2.0	(0.4)	(2.7)	(1.1)
Balance as of December 31st	$ (4.4)	$ (0.5)	$ (55.1)	$ (60.0)	$ (6.2)	$ —	$ (60.2)	$ (66.4)

Eversource's qualified cash flow hedging instruments represent interest rate swap agreements on debt issuances that were settled in prior years. The settlement amount was recorded in AOCI and is being amortized into Net Income over the term of the underlying debt instrument. CL&P, NSTAR Electric and PSNH continue to amortize interest rate swaps settled in prior years from AOCI into Interest Expense over the remaining life of the associated long-term debt. Such interest rate swaps are not material to their respective financial statements.

Defined benefit plan OCI amounts before reclassifications relate to actuarial gains and losses that arose during the year and were recognized in AOCI. The unamortized actuarial gains and losses and prior service costs on the defined benefit plans are amortized from AOCI into Other Income, Net over the average future employee service period, and are reflected in amounts reclassified from AOCI. The related tax effects recognized in AOCI were net deferred tax liabilities of $0.2 million in 2018, and deferred tax assets of $4.1 million and $4.0 million in 2017 and 2016, respectively.

The following table sets forth the amounts reclassified from AOCI by component and the impacted line item on the statements of income:

Eversource *(Millions of Dollars)*	Amounts Reclassified from AOCI For the Years Ended December 31, 2018	2017	2016	Statements of Income Line Item Impacted
Qualified Cash Flow Hedging Instruments	$ (2.8)	$ (3.3)	$ (3.5)	Interest Expense
Tax Effect	1.0	1.3	1.4	Income Tax Expense
Qualified Cash Flow Hedging Instruments, Net of Tax	$ (1.8)	$ (2.0)	$ (2.1)	
Defined Benefit Plan Costs:				
Amortization of Actuarial Losses	$ (6.0)	$ (6.2)	$ (5.6)	Other Income, Net (1)
Amortization of Prior Service Cost	(0.4)	(1.1)	(0.8)	Other Income, Net (1)
Total Defined Benefit Plan Costs	(6.4)	(7.3)	(6.4)	
Tax Effect	1.6	2.8	2.5	Income Tax Expense
Defined Benefit Plan Costs, Net of Tax	$ (4.8)	$ (4.5)	$ (3.9)	
Total Amounts Reclassified from AOCI, Net of Tax	$ (6.6)	$ (6.5)	$ (6.0)	

(1) These amounts are included in the computation of net periodic Pension, SERP and PBOP costs. See Note 1N, "Summary of Significant Accounting Policies – Other Income, Net" and Note 10A, "Employee Benefits – Pension Benefits and Postretirement Benefits Other Than Pension," for further information.

As of December 31, 2018, it is estimated that a pre-tax amount of $2.5 million ($0.7 million for NSTAR Electric and $1.8 million for PSNH) will be reclassified from AOCI as a decrease to Net Income over the next 12 months as a result of the amortization of the interest rate swap agreements which have been settled. In addition, it is estimated that a pre-tax amount of $6.3 million will be reclassified from AOCI as a decrease to Net Income over the next 12 months as a result of the amortization of Pension, SERP and PBOP costs.

17. DIVIDEND RESTRICTIONS

Eversource parent's ability to pay dividends may be affected by certain state statutes, the ability of its subsidiaries to pay common dividends and the leverage restriction tied to its consolidated total debt to total capitalization ratio requirement in its revolving credit agreement. Pursuant to the joint revolving credit agreement of Eversource, CL&P, PSNH, Yankee Gas and NSTAR Gas, and to the NSTAR Electric revolving credit agreement, each company is required to maintain consolidated total indebtedness to total capitalization ratio of no greater than 65 percent at the end of each fiscal quarter. As of December 31, 2018, all companies were in compliance with such covenant. Eversource, CL&P, NSTAR Electric, PSNH, Yankee Gas and NSTAR Gas were in compliance with all such provisions of the revolving credit agreements that may restrict the payment of dividends as of December 31, 2018.

The Retained Earnings balances subject to dividend restrictions were $4.0 billion for Eversource, $1.7 billion for CL&P, $2.1 billion for NSTAR Electric and $627.3 million for PSNH as of December 31, 2018.

CL&P, NSTAR Electric and PSNH are subject to Section 305 of the Federal Power Act that makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in its capital account." Management believes that this Federal Power Act restriction, as applied to CL&P, NSTAR Electric and PSNH, would not be construed or applied by the FERC to prohibit the payment of dividends from retained earnings for lawful and legitimate business purposes. In addition, certain state statutes may impose additional limitations on such companies and on Yankee Gas and NSTAR Gas. Such state law restrictions do not restrict the payment of dividends from retained earnings or net income.

18. COMMON SHARES

The following table sets forth the Eversource parent common shares and the shares of common stock of CL&P, NSTAR Electric and PSNH that were authorized and issued, as well as the respective per share par values:

	Shares			
	Par Value	Authorized as of December 31, 2018 and 2017	Issued as of December 31,	
			2018	2017
Eversource	$ 5	380,000,000	333,878,402	333,878,402
CL&P	$ 10	24,500,000	6,035,205	6,035,205
NSTAR Electric	$ 1	100,000,000	200	200
PSNH	$ 1	100,000,000	301	301

As of both December 31, 2018 and 2017, there were 16,992,594 Eversource common shares held as treasury shares. As of both December 31, 2018 and 2017, there were 316,885,808 Eversource common shares outstanding.

19. PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION

The CL&P and NSTAR Electric preferred stock is not subject to mandatory redemption and is presented as a noncontrolling interest of a subsidiary in Eversource's financial statements.

CL&P is authorized to issue up to 9,000,000 shares of preferred stock, par value $50 per share, and NSTAR Electric is authorized to issue 2,890,000 shares of preferred stock, par value $100 per share. Holders of preferred stock of CL&P and NSTAR Electric are entitled to receive cumulative dividends in preference to any payment of dividends on the common stock. Upon liquidation, holders of preferred stock of CL&P and NSTAR Electric are entitled to receive a liquidation preference before any distribution to holders of common stock in an amount equal to the par value of the preferred stock plus accrued and unpaid dividends. If the net assets were to be insufficient to pay the liquidation preference in full, then the net assets would be distributed ratably to all holders of preferred stock. The preferred stock of CL&P and NSTAR Electric is subject to optional redemption by the CL&P and NSTAR Electric Board of Directors at any time.

Details of preferred stock not subject to mandatory redemption are as follows (in millions, except in redemption price and shares):

Series		Redemption Price Per Share	Shares Outstanding as of December 31,		As of December 31,	
			2018	2017	2018	2017
CL&P						
$1.90	Series of 1947	$ 52.50	163,912	163,912	$ 8.2	$ 8.2
$2.00	Series of 1947	$ 54.00	336,088	336,088	16.8	16.8
$2.04	Series of 1949	$ 52.00	100,000	100,000	5.0	5.0
$2.20	Series of 1949	$ 52.50	200,000	200,000	10.0	10.0
3.90%	Series of 1949	$ 50.50	160,000	160,000	8.0	8.0
$2.06	Series E of 1954	$ 51.00	200,000	200,000	10.0	10.0
$2.09	Series F of 1955	$ 51.00	100,000	100,000	5.0	5.0
4.50%	Series of 1956	$ 50.75	104,000	104,000	5.2	5.2
4.96%	Series of 1958	$ 50.50	100,000	100,000	5.0	5.0
4.50%	Series of 1963	$ 50.50	160,000	160,000	8.0	8.0
5.28%	Series of 1967	$ 51.43	200,000	200,000	10.0	10.0
$3.24	Series G of 1968	$ 51.84	300,000	300,000	15.0	15.0
6.56%	Series of 1968	$ 51.44	200,000	200,000	10.0	10.0
Total CL&P			2,324,000	2,324,000	$ 116.2	$ 116.2
NSTAR Electric						
4.25%	Series of 1956	$ 103.625	180,000	180,000	$ 18.0	$ 18.0
4.78%	Series of 1958	$ 102.80	250,000	250,000	25.0	25.0
Total NSTAR Electric			430,000	430,000	$ 43.0	$ 43.0
Fair Value Adjustment due to Merger with NSTAR					(3.6)	(3.6)
Other						
6.00%	Series of 1958	$ 100.00	23	23	$ —	$ —
Total Eversource - Preferred Stock of Subsidiaries					$ 155.6	$ 155.6

20. COMMON SHAREHOLDERS' EQUITY AND NONCONTROLLING INTERESTS

Dividends on the preferred stock of CL&P and NSTAR Electric totaled $7.5 million for each of the years ended December 31, 2018, 2017 and 2016. These dividends were presented as Net Income Attributable to Noncontrolling Interests on the Eversource statements of income. Noncontrolling Interest – Preferred Stock of Subsidiaries on the Eversource balance sheets totaled $155.6 million as of December 31, 2018 and 2017. On the Eversource balance sheets, Common Shareholders' Equity was fully attributable to Eversource parent and Noncontrolling Interest – Preferred Stock of Subsidiaries was fully attributable to the noncontrolling interest.

For the years ended December 31, 2018, 2017 and 2016, there was no change in ownership of the common equity of CL&P and NSTAR Electric.

21. EARNINGS PER SHARE

Basic EPS is computed based upon the weighted average number of common shares outstanding during each period. Diluted EPS is computed on the basis of the weighted average number of common shares outstanding plus the potential dilutive effect of certain share-based compensation awards as if they were converted into common shares. The dilutive effect of unvested RSU and performance share awards is calculated using the treasury stock method. RSU and performance share awards are included in basic weighted average common shares outstanding as of the date that all necessary vesting conditions have been satisfied.

The following table sets forth the components of basic and diluted EPS:

Eversource *(Millions of Dollars, except share information)*	**For the Years Ended December 31,**		
	2018	**2017**	**2016**
Net Income Attributable to Common Shareholders	$ 1,033.0	$ 988.0	$ 942.3
Weighted Average Common Shares Outstanding:			
Basic	317,370,369	317,411,097	317,650,180
Dilutive Effect	623,565	620,483	804,059
Diluted	317,993,934	318,031,580	318,454,239
Basic EPS	$ 3.25	$ 3.11	$ 2.97
Diluted EPS	$ 3.25	$ 3.11	$ 2.96

22. REVENUES

On January 1, 2018, Eversource, including CL&P, NSTAR Electric and PSNH, adopted ASU 2014-09, "*Revenue from Contracts with Customers (Topic 606)*" using the modified retrospective approach. The core principle of this accounting guidance is that revenue is recognized when promised goods or services (referred to as performance obligations) are transferred to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The new standard uses a five-step model for recognizing and measuring revenue from contracts with customers, which includes identifying the contract with the customer, identifying the performance obligations promised within the contract, determining the transaction price (the amount of consideration to which the company expects to be entitled), allocating the transaction price to the performance obligations and recognizing revenue when (or as) the performance obligation is satisfied.

The following table presents operating revenues disaggregated by revenue source:

	For the Year Ended December 31, 2018						
Eversource *(Millions of Dollars)*	**Electric Distribution**	**Natural Gas Distribution**	**Electric Transmission**	**Water Distribution**	**Other**	**Eliminations**	**Total**
Revenue from Contracts with Customers							
Retail Tariff Sales							
Residential	$ 3,766.6	$ 542.5	$ —	$ 130.7	$ —	$ —	$ 4,439.8
Commercial	2,634.7	334.8	—	63.3	—	(4.5)	3,028.3
Industrial	351.9	96.0	—	4.4	—	(10.0)	442.3
Total Retail Tariff Sales Revenue	6,753.2	973.3	—	198.4	—	(14.5)	7,910.4
Wholesale Transmission Revenue	—	—	1,308.9	—	47.3	(1,092.2)	264.0
Wholesale Market Sales Revenue	179.5	57.5	—	4.1	—	—	241.1
Other Revenue from Contracts with Customers	65.9	(2.2)	12.6	7.2	889.0	(891.0)	81.5
Reserve for Revenue Subject to Refund	(12.3)	(8.3)	—	(3.7)	—	—	(24.3)
Total Revenue from Contracts with Customers	6,986.3	1,020.3	1,321.5	206.0	936.3	(1,997.7)	8,472.7
Alternative Revenue Programs	(47.0)	(1.2)	(35.2)	5.4	—	31.9	(46.1)
Other Revenue	17.9	3.1	—	0.6	—	—	21.6
Total Operating Revenues	$ 6,957.2	$ 1,022.2	$ 1,286.3	$ 212.0	$ 936.3	$ (1,965.8)	$ 8,448.2

	For the Year Ended December 31, 2018		
(Millions of Dollars)	**CL&P**	**NSTAR Electric**	**PSNH**
Revenue from Contracts with Customers			
Retail Tariff Sales			
Residential	$ 1,828.2	$ 1,380.9	$ 557.5
Commercial	928.1	1,391.5	316.9
Industrial	147.7	124.9	79.3
Total Retail Tariff Sales Revenue	2,904.0	2,897.3	953.7
Wholesale Transmission Revenue	620.6	488.8	199.5
Wholesale Market Sales Revenue	48.3	76.1	56.6
Other Revenue from Contracts with Customers	35.0	28.9	15.5
Reserve for Revenue Subject to Refund	—	—	(12.3)
Total Revenue from Contracts with Customers	3,607.9	3,491.1	1,213.0
Alternative Revenue Programs	(65.9)	0.9	(17.3)
Other Revenue	8.5	8.3	1.1
Eliminations	(454.3)	(387.4)	(149.2)
Total Operating Revenues	$ 3,096.2	$ 3,112.9	$ 1,047.6

Retail Tariff Sales: Regulated utilities provide products and services to their regulated customers under rates, pricing, payment terms and conditions of service, regulated by each state regulatory agency. The arrangement whereby a utility provides commodity service to a customer for a price approved by the respective state regulatory commission is referred to as a tariff sale contract, and the tariff governs all aspects of the provision of

regulated services by utilities. The majority of revenue for Eversource, CL&P, NSTAR Electric and PSNH is derived from regulated retail tariff sales for the sale and distribution of electricity, natural gas and water to residential, commercial and industrial retail customers.

The utility's performance obligation for the regulated tariff sales is to provide electricity, natural gas or water to the customer as demanded. The promise to provide the commodity represents a single performance obligation, as it is a promise to transfer a series of distinct goods or services that are substantially the same and that have the same pattern of transfer to the customer. Revenue is recognized over time as the customer simultaneously receives and consumes the benefits provided by the utility, and the utility satisfies its performance obligation. Revenue is recognized based on the output method as there is a directly observable output to the customer (electricity, natural gas or water units delivered to the customer and immediately consumed). Each Eversource utility is entitled to be compensated for performance completed to date (service taken by the customer) until service is terminated.

In regulated tariff sales, the transaction prices are the rates approved by the respective state regulatory commissions. In general, rates can only be changed through formal proceedings with the state regulatory commissions. These rates are designed to recover the costs to provide service to customers and include a return on investment. Regulatory commission-approved tracking mechanisms are included in these rates and are also used to recover, on a fully-reconciling basis, certain costs, such as the procurement of energy supply, retail transmission charges, energy efficiency program costs, net metering for distributed generation, and restructuring and stranded costs. These tracking mechanisms result in rates being changed periodically to ensure recovery of actual costs incurred.

Customers may elect to purchase electricity from each Eversource electric utility or may contract separately with a competitive third party supplier. Revenue is not recorded for the sale of the electricity commodity to customers who have contracted separately with these suppliers, only the delivery to a customer, as the utility is acting as an agent on behalf of the third party supplier.

Wholesale Transmission Revenues: The Eversource electric transmission-owning companies (CL&P, NSTAR Electric and PSNH) each own and maintain transmission facilities that are part of an interstate power transmission grid over which electricity is transmitted throughout New England. CL&P, NSTAR Electric and PSNH, as well as most other New England utilities, are parties to a series of agreements that provide for coordinated planning and operation of the region's transmission facilities and the rules by which they acquire transmission services. The Eversource electric transmission-owning companies have a combination of FERC-approved regional and local formula rates that work in tandem to recover all their transmission costs. These rates are part of the ISO-NE Tariff. Regional rates recover the costs of higher voltage transmission facilities that benefit the region and are collected from all New England transmission customers, including the Eversource distribution businesses. Eversource's local rates recover the companies' total transmission revenue requirements, less revenues received from regional rates and other sources, and are collected from Eversource's distribution businesses and other transmission customers. The distribution businesses of Eversource, in turn, recover the FERC approved charges from retail customers through annual or semiannual tracking mechanisms, which are retail tariff sales.

The utility's performance obligation for regulated wholesale transmission sales is to provide transmission services to the customer as demanded. The promise to provide transmission service represents a single performance obligation. The transaction prices are the transmission rate formulas as defined by the ISO-NE Tariff and are regulated and established by FERC. Wholesale transmission revenue is recognized over time as the performance obligation is completed, which occurs as transmission services are provided to customers. The revenue is recognized based on the output method. Each Eversource utility is entitled to be compensated for performance completed to date (e.g., use of the transmission system by the customer).

Wholesale Market Sales Revenues: Wholesale market sales transactions include sales of energy and energy-related products into the ISO-NE wholesale electricity market, sales of natural gas to third party marketers, and also the sale of RECs to various counterparties. ISO-NE oversees the region's wholesale electricity market and administers the transactions and terms and conditions, including payment terms, which are established in the ISO-NE tariff, between the buyers and sellers in the market. Pricing is set by the wholesale market. The wholesale transactions in the ISO-NE market occur on a day-ahead basis or a real-time basis (daily) and are, therefore, short-term. Transactions are tracked and reported by ISO-NE net by the hour, which is the net hourly position of energy sales and purchases by each market participant. Beginning in the first quarter of 2018, the performance obligation for ISO-NE energy transactions is defined to be the net by hour transaction. Revenue is recognized when the performance obligation for these energy sales transactions is satisfied, when the sale occurs and the energy is transferred to the customer. For sales of natural gas, transportation, and natural gas pipeline capacity to third party marketers, revenue is recognized when the performance obligation is satisfied at the point in time the sale occurs and the natural gas or related product is transferred to the marketer. RECs are sold to various counterparties, and revenue is recognized when the performance obligation is satisfied upon transfer of title to the customer through the New England Power Pool Generation Information System.

Other Revenue from Contracts with Customers: Other revenue from contracts with customers primarily includes property rentals that are not deemed leases. These revenues are generally recognized on a straight-line basis over time as the service is provided to the customer.

Reserve for Revenue Subject to Refund: Current base rates include an estimate of income taxes, which was based on the U.S. federal corporate income tax rate in effect at the time of the rate proceeding. Eversource established a regulatory liability, recorded as a reduction to revenue, to reflect the difference between the 35 percent federal corporate income tax rate included in rates charged to customers and the 21 percent federal corporate income tax rate, effective January 1, 2018 as a result of the Tax Cuts and Jobs Act, until rates billed to customers reflect the lower federal tax rate. Effective May 1, 2018, CL&P adjusted rates billed to customers to reflect the lower federal income tax rate prospectively and, as of December 31, 2018, fully refunded its regulatory liability associated with the higher federal corporate income tax rate billed to customers in the period between January 1, 2018 through April 30, 2018. Effective November 15, 2018, Yankee Gas adjusted distribution rates to reflect the lower federal income tax rate prospectively and to refund its regulatory liability associated with the higher federal corporate income tax rate billed to customers in the period between January 1, 2018 through November 14, 2018. Although Yankee Gas' new rates were effective January 1, 2019, the provisions of the settlement agreement took effect November 15, 2018. For NSTAR Electric and NSTAR Gas, a December 2018 DPU order indicated that the DPU will not require a revision to base rates for any potential refunds associated with the higher federal corporate income tax rate billed to customers in the period between January 1, 2018 to the effective dates of each company's rate changes (effective February 1, 2018 for NSTAR Electric and July 1, 2018 for NSTAR Gas). PSNH and Aquarion will refund the overcollection in distribution rates from January 1, 2018 to customers in a future period. PSNH will adjust distribution rates to reflect the prospective lower federal income tax rate effective July 1, 2019, or earlier if a rate case is filed for rates effective prior to July 1, 2019.

Alternative Revenue Programs: In accordance with accounting guidance for rate-regulated operations, certain of Eversource's utilities' rate making mechanisms qualify as alternative revenue programs ("ARPs") if they meet specified criteria, in which case revenues may be recognized prior to billing based on allowed levels of collection in rates. Eversource's utility companies recognize revenue and record a regulatory asset or liability once the condition or event allowing for the automatic adjustment of future rates occurs. ARP revenues include both the recognition of the deferral adjustment to ARP revenues, when the regulator-specified condition or event allowing for additional billing or refund has occurred, and an equal and offsetting reversal of the ARP deferral to revenues as those amounts are reflected in the price of service in subsequent periods.

Eversource’s ARPs include the revenue decoupling mechanism and the annual reconciliation adjustment to transmission formula rates, described below.

- Certain Eversource electric, natural gas and water companies, including CL&P and NSTAR Electric, have revenue decoupling mechanisms approved by a regulatory commission ("decoupled companies"). Decoupled companies’ distribution revenues are not directly based on sales volumes. The decoupled companies reconcile their annual base distribution rate recovery to pre-established levels of baseline distribution delivery service revenues, with any difference between the allowed level of distribution revenue and the actual amount realized adjusted through subsequent rates.

- The transmission formula rates provide for the annual reconciliation and recovery or refund of estimated costs to actual costs. The

financial impacts of differences between actual and estimated costs are deferred for future recovery from, or refund to, transmission customers. This transmission deferral reconciles billed transmission revenues to the revenue requirement for our transmission businesses.

Other Revenues: Other Revenues include certain fees charged to customers and lease revenue that are not considered revenue from contracts with customers.

Intercompany Eliminations: Intercompany eliminations are primarily related to the Eversource electric transmission revenues that are derived from ISO-NE regional transmission charges to the distribution businesses of CL&P, NSTAR Electric and PSNH that recover the costs of the wholesale transmission business, and revenues from Eversource's service company. Intercompany revenues and expenses between the Eversource wholesale transmission businesses and the Eversource distribution businesses and from Eversource's service company are eliminated in consolidation and included in "Eliminations" in the table above.

Receivables: Receivables, Net on the balance sheet include trade receivables from our retail customers and receivables arising from ISO-NE billing related to wholesale transmission contracts and wholesale market transactions, sales of natural gas and capacity to marketers, sales of RECs, and property rentals. In general, retail tariff customers and wholesale transmission customers are billed monthly and the payment terms are generally due and payable upon receipt of the bill.

Unbilled Revenues: Unbilled Revenues on the balance sheet represent estimated amounts due from retail customers for electricity, natural gas or water delivered to customers but not yet billed. The utility company has satisfied its performance obligation and the customer has received and consumed the commodity as of the balance sheet date, and therefore, the utility company records revenue for those services in the period the services were provided. Only the passage of time is required before the company is entitled to payment for the satisfaction of the performance obligation. Payment from customers is due monthly as services are rendered and amounts are billed. Actual amounts billed to customers when meter readings become available may vary from the estimated amount.

Unbilled revenues are recognized by allocating estimated unbilled sales volumes to the respective customer classes, and then applying an estimated rate by customer class to those sales volumes. Unbilled revenue estimates reflect seasonality, weather, customer usage patterns, customer rates in effect for customer classes, and the timing of customer billing. The companies that have a decoupling mechanism record a regulatory deferral to reflect the actual allowed amount of revenue associated with their respective decoupled distribution rate design.

Practical Expedients: Eversource has elected practical expedients in the accounting guidance that allow the company to record revenue in the amount that the company has a right to invoice, if that amount corresponds directly with the value to the customer of the company's performance to date, and not to disclose related unsatisfied performance obligations. Retail and wholesale transmission tariff sales fall into this category, as these sales are recognized as revenue in the period the utility provides the service and completes the performance obligation, which is the same as the monthly amount billed to customers. There are no other material revenue streams for which Eversource has unsatisfied performance obligations.

23. SEGMENT INFORMATION

Eversource is organized among the Electric Distribution, Electric Transmission, Natural Gas Distribution and Water Distribution reportable segments and Other based on a combination of factors, including the characteristics of each segments' services, the sources of operating revenues and expenses and the regulatory environment in which each segment operates. These reportable segments represent substantially all of Eversource's total consolidated revenues. Revenues from the sale of electricity, natural gas and water primarily are derived from residential, commercial and industrial customers and are not dependent on any single customer. The Electric Distribution reportable segment includes the results of PSNH's generation facilities prior to sales in January and August 2018, and NSTAR Electric's solar power facilities. Eversource's reportable segments are determined based upon the level at which Eversource's chief operating decision maker assesses performance and makes decisions about the allocation of company resources. On December 4, 2017, Eversource acquired Aquarion, which was considered to be a new operating segment, Water Distribution. Though the water distribution segment does not meet quantitative thresholds under the segment reporting accounting guidance, based on qualitative factors including the nature of the water distribution business, Water Distribution was deemed a reportable segment beginning in 2018.

The remainder of Eversource's operations is presented as Other in the tables below and primarily consists of 1) the equity in earnings of Eversource

parent from its subsidiaries and intercompany interest income, both of which are eliminated in consolidation, and interest expense related to the debt of Eversource parent, 2) the revenues and expenses of Eversource Service, most of which are eliminated in consolidation, 3) the operations of CYAPC and YAEC, 4) Eversource Water Ventures, Inc., parent company of Aquarion, and 5) the results of other unregulated subsidiaries, which are not part of its core business. In addition, Other in the tables below includes Eversource parent's equity ownership interests in certain natural gas pipeline projects owned by Enbridge, Inc., the Bay State Wind project, a renewable energy investment fund, and two companies that transmit hydroelectricity imported from the Hydro-Quebec system in Canada. In the ordinary course of business, Yankee Gas and NSTAR Gas purchase natural gas transmission services from the Enbridge, Inc. natural gas pipeline projects described above. These affiliate transaction costs total approximately $62.5 million annually and are classified as Purchased Power, Fuel and Transmission on the Eversource statements of income.

Each of Eversource's subsidiaries, including CL&P, NSTAR Electric and PSNH, has one reportable segment.

The Electric Transmission segment includes a reduction to Operations and Maintenance expense of $27.5 million in 2016 for costs incurred in previous years that was recovered in transmission rates over the period June 1, 2016 through May 31, 2017. These costs were associated with the merger of Northeast Utilities and NSTAR.

Cash flows used for investments in plant included in the segment information below are cash capital expenditures that do not include amounts incurred but not paid, cost of removal, AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense.

Eversource's segment information is as follows:

	For the Year Ended December 31, 2018 (1)						
Eversource *(Millions of Dollars)*	**Electric Distribution**	**Natural Gas Distribution**	**Electric Transmission**	**Water Distribution**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 6,957.2	$ 1,022.2	$ 1,286.3	$ 212.0	$ 936.3	$ (1,965.8)	$ 8,448.2
Depreciation and Amortization	(671.8)	(75.0)	(231.8)	(46.5)	(49.1)	2.2	(1,072.0)
Other Operating Expenses	(5,548.6)	(787.6)	(375.5)	(99.8)	(831.5)	1,966.7	(5,676.3)
Operating Income	736.8	159.6	679.0	65.7	55.7	3.1	1,699.9
Interest Expense	(202.8)	(44.1)	(120.6)	(34.3)	(129.3)	32.3	(498.8)
Interest Income	18.7	—	2.4	—	30.3	(33.3)	18.1
Other Income/(Loss), Net	67.5	7.1	31.1	(0.4)	1,185.3	(1,180.3)	110.3
Income Tax (Expense)/Benefit	(160.2)	(29.4)	(161.8)	(0.1)	62.5	—	(289.0)
Net Income	460.0	93.2	430.1	30.9	1,204.5	(1,178.2)	1,040.5
Net Income Attributable to Noncontrolling Interests	(4.6)	—	(2.9)	—	—	—	(7.5)
Net Income Attributable to Common Shareholders	$ 455.4	$ 93.2	$ 427.2	$ 30.9	$ 1,204.5	$ (1,178.2)	$ 1,033.0
Total Assets (as of)	$ 21,389.1	$ 3,904.9	$ 10,285.0	$ 2,253.0	$ 17,874.2	$ (17,464.9)	$ 38,241.3
Cash Flows Used for Investments in Plant	$ 961.3	$ 351.5	$ 929.7	$ 102.3	$ 178.6	$ —	$ 2,523.4

Eversource *(Millions of Dollars)*	For the Year Ended December 31, 2017 (2)						
	Electric Distribution	Natural Gas Distribution	Electric Transmission	Water Distribution	Other	Eliminations	Total
Operating Revenues	$ 5,542.9	$ 947.3	$ 1,301.7	$ 15.9	$ 931.0	$ (986.8)	$ 7,752.0
Depreciation and Amortization	(542.6)	(72.9)	(209.4)	(3.7)	(37.4)	2.2	(863.8)
Other Operating Expenses	(4,072.6)	(716.4)	(382.8)	(8.3)	(806.6)	986.7	(5,000.0)
Operating Income	927.7	158.0	709.5	3.9	87.0	2.1	1,888.2
Interest Expense	(186.3)	(43.1)	(115.1)	(3.1)	(90.0)	15.8	(421.8)
Interest Income	7.3	0.1	1.8	0.1	15.7	(16.7)	8.3
Other Income/(Loss), Net	41.6	3.8	27.3	—	1,113.0	(1,086.0)	99.7
Income Tax Expense	(288.3)	(44.2)	(228.7)	(2.1)	(15.5)	(0.1)	(578.9)
Net Income/(Loss)	502.0	74.6	394.8	(1.2)	1,110.2	(1,084.9)	995.5
Net Income Attributable to Noncontrolling Interests	(4.6)	—	(2.9)	—	—	—	(7.5)
Net Income/(Loss) Attributable to Common Shareholders	$ 497.4	$ 74.6	$ 391.9	$ (1.2)	$ 1,110.2	$ (1,084.9)	$ 988.0
Total Assets (as of)	$ 19,250.4	$ 3,595.2	$ 9,401.2	$ 2,182.9	$ 16,220.9	$ (14,430.2)	$ 36,220.4
Cash Flows Used for Investments in Plant	$ 1,020.7	$ 298.2	$ 867.6	$ 16.0	$ 145.6	$ —	$ 2,348.1

Eversource *(Millions of Dollars)*	For the Year Ended December 31, 2016 (2)						
	Electric Distribution	Natural Gas Distribution	Electric Transmission	Water Distribution	Other	Eliminations	Total
Operating Revenues	$ 5,594.3	$ 857.7	$ 1,210.0	$ —	$ 870.4	$ (893.3)	$ 7,639.1
Depreciation and Amortization	(504.7)	(65.3)	(185.8)	—	(33.5)	2.2	(787.1)
Other Operating Expenses	(4,173.0)	(629.0)	(321.3)	—	(779.2)	891.8	(5,010.7)
Operating Income	916.6	163.4	702.9	—	57.7	0.7	1,841.3
Interest Expense	(193.1)	(41.3)	(110.0)	—	(63.5)	6.9	(401.0)
Interest Income	10.0	0.1	1.2	—	7.0	(7.3)	11.0
Other Income, Net	22.7	0.7	17.8	—	1,021.2	(1,008.9)	53.5
Income Tax (Expense)/Benefit	(288.8)	(45.2)	(238.2)	—	16.5	0.7	(555.0)
Net Income	467.4	77.7	373.7	—	1,038.9	(1,007.9)	949.8
Net Income Attributable to Noncontrolling Interests	(4.6)	—	(2.9)	—	—	—	(7.5)
Net Income Attributable to Common Shareholders	$ 462.8	$ 77.7	$ 370.8	$ —	$ 1,038.9	$ (1,007.9)	$ 942.3
Cash Flows Used for Investments in Plant	$ 812.6	$ 255.3	$ 801.0	$ —	$ 108.0	$ —	$ 1,976.9

(1) Effective January 1, 2018, upon implementation of the new revenue accounting guidance, the electric distribution segment is presented gross and intercompany transmission billings are presented in the eliminations column, as Eversource believes that the electric distribution segment acts as a principal, rather than an agent, in its contracts with retail customers. Retail customers contract directly with the electric distribution utility and do not differentiate between distribution and transmission services. Therefore, the electric distribution segment revenues, which are derived from retail customer billings, are presented gross of the eliminations. Prior to 2018, the electric distribution segment presented intercompany electric transmission billings net, based on indicators of net presentation prior to the new revenue guidance. See Note 22 "Revenues," to the financial statements regarding accounting for revenues.

(2) As a result of the adoption of new accounting guidance, the non-service related components of pension, SERP and PBOP benefit costs are presented as non-operating income and recorded in Other Income, Net on the statements of income. The 2017 and 2016 amounts, which were previously presented within Operations and Maintenance expense on the statements of income, have been retrospectively presented within Other Income, Net for the years ended December 31, 2017 and 2016. See Note 1C, "Summary of Significant Accounting Policies - Accounting Standards" and Note 1N, "Summary of Significant Accounting Policies - Other Income, Net," to the financial statements for further information.

(3) The water distribution business was determined to be a reportable segment beginning in 2018. The 2017 segment information has been recast to conform to the current segment reporting structure.

24. ACQUISITION OF AQUARION AND GOODWILL

A. Acquisition of Aquarion

On December 4, 2017, Eversource acquired Aquarion for a purchase price of $1.675 billion, consisting of approximately $880 million in cash and $795 million of assumed Aquarion debt. Aquarion is a holding company that owns three separate regulated water utility subsidiaries engaged in the water collection, treatment and distribution business that operate in Connecticut, Massachusetts and New Hampshire. These regulated utilities collect, treat and distribute water to residential, commercial and industrial customers, to other utilities for resale, and for private and municipal fire protection. Aquarion and its subsidiaries became wholly-owned subsidiaries of Eversource, and Eversource's consolidated financial information includes Aquarion and its subsidiaries' activity beginning December 4, 2017. The approximate $880 million cash purchase price included the $745 million equity purchase price plus a $135 million shareholder loan that was repaid at closing.

Purchase Price Allocation: The purchase price allocation reflects a measurement period adjustment recorded in the first quarter of 2018 to revise the fair value of Aquarion's regulated debt. The $7.9 million increase to the fair value of Long-Term Debt (including the current portion) and corresponding increase to Regulatory Assets, included within Other Noncurrent Assets, excluding Goodwill in the table below, will be amortized over the life of the related debt. The allocation of the cash purchase price was as follows:

Millions of Dollars)		
Current Assets	$	41.2
PP&E		1,034.9
Goodwill		907.9
Other Noncurrent Assets, excluding Goodwill		215.5
Current Liabilities		(121.9)
Noncurrent Liabilities		(421.6)
Long-Term Debt		(778.3)
Total Cash Purchase Price	$	877.7

Pro Forma Financial Information: The following unaudited pro forma financial information reflects the pro forma combined results of operations of Eversource and Aquarion and reflects the amortization of purchase price adjustments assuming the acquisition had taken place on January 1, 2016. The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or the future consolidated results of operations of Eversource.

	For the Years Ended December 31,	
(Pro forma amounts in millions, except share amounts)	**2017**	**2016**
Operating Revenues	$ 7,947.7	$ 7,849.0
Net Income Attributable to Common Shareholders	1,019.1	969.3
Basic EPS	3.21	3.05
Diluted EPS	3.20	3.04

Aquarion Revenues and Pre-Tax Income: The impact of Aquarion on Eversource's accompanying consolidated statement of income included operating revenues of $15.9 million and pre-tax income of $1.1 million for the year ended December 31, 2017.

B. Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Goodwill is evaluated for impairment at least annually and more frequently if indicators of impairment arise. In accordance with the accounting standards, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. Goodwill is not subject to amortization, however is subject to a fair value based assessment for impairment at least annually and whenever facts or circumstances indicate that there may be an impairment. A resulting write-down, if any, would be charged to Operating Expenses.

Eversource completed the acquisition of Aquarion on December 4, 2017, resulting in the addition of $0.9 billion of goodwill. Upon completion of the acquisition, Eversource determined that the reporting units for the purpose of testing goodwill are Electric Distribution, Electric Transmission, Natural Gas Distribution and Water Distribution. The goodwill resulting from the Aquarion acquisition has been entirely allocated to the Water Distribution reporting unit. These reporting units are consistent with the operating segments underlying the reportable segments identified in Note 23, "Segment Information," to the financial statements.

Eversource completed its annual goodwill impairment test for Electric Distribution, Electric Transmission, Natural Gas Distribution and Water Distribution reporting units as of October 1, 2018 and determined that no impairment existed. There were no events subsequent to October 1, 2018 that indicated impairment of goodwill. The annual goodwill assessment included an evaluation of the Company's share price and credit ratings, analyst reports, financial performance, cost and risk factors, long-term strategy, growth and future projections, as well as macroeconomic, industry and market conditions. This evaluation required the consideration of several factors that impact the fair value of the reporting units, including conditions and assumptions that affect the future cash flows of the reporting units. Key considerations include discount rates, utility sector market performance and merger transaction multiples, and internal estimates of future cash flows and net income.

The following table presents goodwill by reportable segment as of December 31, 2018 and 2017:

(Billions of Dollars)	Electric Distribution	Electric Transmission	Natural Gas Distribution	Water Distribution	Total
Goodwill	$ 2.5	$ 0.6	$ 0.4	$ 0.9	$ 4.4

25. QUARTERLY FINANCIAL DATA (UNAUDITED)

Eversource *(Millions of Dollars, except per share information)*	Quarter Ended							
	2018				2017			
	March 31,	June 30,	September 30,	December 31,	March 31,	June 30,	September 30,	December 31,
Operating Revenues	$ 2,288.0	$ 1,853.9	$ 2,271.4	$ 2,034.9	$ 2,105.1	$ 1,762.8	$ 1,988.5	$ 1,895.6
Operating Income	442.5	391.4	466.0	400.0	501.0	448.2	495.3	443.7
Net Income	271.4	244.6	291.3	233.2	261.3	232.6	262.2	239.4
Net Income Attributable to Common Shareholders	269.5	242.8	289.4	231.3	259.5	230.7	260.4	237.4
Basic and Diluted EPS (1)	$ 0.85	$ 0.76	$ 0.91	$ 0.73	$ 0.82	$ 0.73	$ 0.82	$ 0.75

(1) The summation of quarterly EPS data may not equal annual data due to rounding.

(Millions of Dollars)	Quarter Ended							
	2018				2017			
	March 31,	June 30,	September 30,	December 31,	March 31,	June 30,	September 30,	December 31,
CL&P								
Operating Revenues	$ 785.0	$ 694.9	$ 865.0	$ 751.3	$ 732.3	$ 666.6	$ 774.8	$ 713.7
Operating Income	157.2	163.1	172.7	142.8	175.5	175.6	177.1	155.2
Net Income	98.6	99.7	100.3	79.1	90.2	91.3	96.1	99.1
NSTAR Electric								
Operating Revenues	$ 770.1	$ 690.7	$ 939.5	$ 712.6	$ 733.8	$ 704.7	$ 851.9	$ 690.2
Operating Income	119.0	133.6	205.5	126.0	156.6	177.9	229.7	124.2
Net Income	77.1	87.9	140.6	77.5	83.4	95.0	125.8	70.5
PSNH								
Operating Revenues	$ 267.4	$ 235.1	$ 290.2	$ 254.9	$ 253.2	$ 230.4	$ 250.0	$ 248.0
Operating Income	55.8	46.9	56.5	37.2	66.6	63.5	66.0	69.8
Net Income	35.1	25.8	40.7	14.3	34.3	31.6	33.7	36.4

GLOSSARY OF TERMS

The following is a glossary of abbreviations and acronyms that are found in this report:

Current or former Eversource Energy companies, segments or investments:

Eversource, ES or the Company	Eversource Energy and subsidiaries
Eversource parent or ES parent	Eversource Energy, a public utility holding company
ES parent and other companies	ES parent and other companies are comprised of Eversource parent, Eversource Service, Eversource Water Ventures, Inc. (parent company of Aquarion), and other subsidiaries, which primarily includes our unregulated businesses, HWP Company, The Rocky River Realty Company (a real estate subsidiary), the consolidated operations of CYAPC and YAEC, and Eversource parent's equity ownership interests that are not consolidated
CL&P	The Connecticut Light and Power Company
NSTAR Electric	NSTAR Electric Company
PSNH	Public Service Company of New Hampshire
PSNH Funding	PSNH Funding LLC 3, a bankruptcy remote, special purpose, wholly-owned subsidiary of PSNH
NSTAR Gas	NSTAR Gas Company
Yankee Gas	Yankee Gas Services Company
Aquarion	Eversource Aquarion Holdings, Inc. and its subsidiaries (formerly known as Macquarie Utilities Inc)
NPT	Northern Pass Transmission LLC
Northern Pass	The HVDC and associated alternating-current transmission line project from Canada into New Hampshire
Eversource Service	Eversource Energy Service Company
Bay State Wind	A project being developed jointly by Eversource and Denmark-based Ørsted (formerly known as DONG Energy) to construct an offshore wind farm off the coast of Massachusetts
CYAPC	Connecticut Yankee Atomic Power Company
MYAPC	Maine Yankee Atomic Power Company
YAEC	Yankee Atomic Electric Company
Yankee Companies	CYAPC, YAEC and MYAPC
Regulated companies	The Eversource regulated companies are comprised of the electric distribution and transmission businesses of CL&P, NSTAR Electric and PSNH, the natural gas distribution businesses of Yankee Gas and NSTAR Gas, NPT, Aquarion, and the solar power facilities of NSTAR Electric

Regulators:

DEEP	Connecticut Department of Energy and Environmental Protection
DOE	U.S. Department of Energy
DOER	Massachusetts Department of Energy Resources
DPU	Massachusetts Department of Public Utilities
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ISO-NE	ISO New England, Inc., the New England Independent System Operator
MA DEP	Massachusetts Department of Environmental Protection
NHPUC	New Hampshire Public Utilities Commission
PURA	Connecticut Public Utilities Regulatory Authority
SEC	U.S. Securities and Exchange Commission
SJC	Supreme Judicial Court of Massachusetts

Other Terms and Abbreviations:

Access Northeast	A project jointly owned by Eversource, Enbridge, Inc. ("Enbridge"), and National Grid plc ("National Grid") through Algonquin Gas Transmission, LLC ("AGT")
ADIT	Accumulated Deferred Income Taxes
AFUDC	Allowance For Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
Bcf	Billion cubic feet
C&LM	Conservation and Load Management
CfD	Contract for Differences
CTA	Competitive Transition Assessment
CWIP	Construction Work in Progress
EDC	Electric distribution company
EPS	Earnings Per Share
ERISA	Employee Retirement Income Security Act of 1974
ESOP	Employee Stock Ownership Plan
Eversource 2017 Form 10-K	The Eversource Energy and Subsidiaries 2017 combined Annual Report on Form 10-K as filed with the SEC
Fitch	Fitch Ratings
FMCC	Federally Mandated Congestion Charge
FTR	Financial Transmission Rights
GAAP	Accounting principles generally accepted in the United States of America
GSC	Generation Service Charge
GSRP	Greater Springfield Reliability Project
GWh	Gigawatt-Hours
HQ	Hydro-Québec, a corporation wholly-owned by the Québec government, including its divisions that produce, transmit and distribute electricity in Québec, Canada
HVDC	High-voltage direct current
Hydro Renewable Energy	Hydro Renewable Energy, Inc., a wholly-owned subsidiary of Hydro-Québec
IPP	Independent Power Producers
ISO-NE Tariff	ISO-NE FERC Transmission, Markets and Services Tariff
kV	Kilovolt
kVa	Kilovolt-ampere
kW	Kilowatt (equal to one thousand watts)
kWh	Kilowatt-Hours (the basic unit of electricity energy equal to one kilowatt of power supplied for one hour)
LBR	Lost Base Revenue
LNG	Liquefied natural gas
LRS	Supplier of last resort service
MG	Million gallons
MGP	Manufactured Gas Plant
MMBtu	One million British thermal units
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.

MW	Megawatt
MWh	Megawatt-Hours
NEEWS	New England East-West Solution
NETOs	New England Transmission Owners (including Eversource, National Grid and Avangrid)
OCI	Other Comprehensive Income/(Loss)
PAM	Pension and PBOP Rate Adjustment Mechanism
PBOP	Postretirement Benefits Other Than Pension
PBOP Plan	Postretirement Benefits Other Than Pension Plan
PCRBs	Pollution Control Revenue Bonds
Pension Plan	Single uniform noncontributory defined benefit retirement plan
PPA	Pension Protection Act
RRBs	Rate Reduction Bonds
RECs	Renewable Energy Certificates
Regulatory ROE	The average cost of capital method for calculating the return on equity related to the distribution and generation business segment excluding the wholesale transmission segment
RNS	Regional Network Service
ROE	Return on Equity
RRB	Rate Reduction Bond or Rate Reduction Certificate
RSUs	Restricted share units
S&P	Standard & Poor's Financial Services LLC
SBC	Systems Benefits Charge
SCRC	Stranded Cost Recovery Charge
SERP	Supplemental Executive Retirement Plans and non-qualified defined benefit retirement plans
SS	Standard service
TCAM	Transmission Cost Adjustment Mechanism
TSA	Transmission Service Agreement
UI	The United Illuminating Company

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	372,456			
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value	(267,417)			
4	Total (lines 2 and 3)	(267,417)			
5	Balance of Account 219 at End of Preceding Quarter/Year	105,039			
6	Balance of Account 219 at Beginning of Current Year	105,039			
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value	8,181			
9	Total (lines 7 and 8)	8,181			
10	Balance of Account 219 at End of Current Quarter/Year	113,220			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [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	(2,366,468)		(1,994,012)		
2					
3	437,326		169,909		
4	437,326		169,909	374,725,977	374,895,886
5	(1,929,142)		(1,824,103)		
6	(1,929,142)		(1,824,103)		
7					
8	437,326		445,507		
9	437,326		445,507	383,090,152	383,535,659
10	(1,491,816)		(1,378,596)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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)	9,511,356,841	9,511,356,841
4	Property Under Capital Leases	4,342,945	4,342,945
5	Plant Purchased or Sold		
6	Completed Construction not Classified	1,375,372,223	1,375,372,223
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	10,891,072,009	10,891,072,009
9	Leased to Others		
10	Held for Future Use	40,942,311	40,942,311
11	Construction Work in Progress	470,314,379	470,314,379
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	11,402,328,699	11,402,328,699
14	Accum Prov for Depr, Amort, & Depl	2,967,931,831	2,967,931,831
15	Net Utility Plant (13 less 14)	8,434,396,868	8,434,396,868
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,910,139,724	2,910,139,724
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	57,792,107	57,792,107
22	Total In Service (18 thru 21)	2,967,931,831	2,967,931,831
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		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,967,931,831	2,967,931,831

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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
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					33

Schedule Page: 200 Line No.: 13 Column: c

Company	Plant in Service (Line 3)	Property Under Capital Leases (Line 4)	CCNC (Line 6)	Held for Future Use (Line 10)	CWIP (Line 11)	Total (Line 13)
East	7,612,055,773	4,342,945	965,785,442	40,774,950	427,941,342	9,050,900,451
West Distribution	920,077,185	-	113,137,093	167,361	23,136,976	1,056,518,615
West Transmission	979,223,883	-	296,449,688		19,236,061	1,294,909,633
Total	**9,511,356,841**	**4,342,945**	**1,375,372,223**	**40,942,311**	**470,314,379**	**11,402,328,699**

Schedule Page: 200 Line No.: 21 Column: c

Company	Function	FERC Account	Total
East	General Plant	111010	7,662,720
	Intangible	111010	28,360,337
	Lease	111020	790,744
East Total			**36,813,801**
West Distribution	General Plant	111010	2,627,548
	Intangible	111010	17,052,308
West Distribution Total			**19,679,856**
West Transmission	Intangible	111010	1,298,450
West Transmission Total			**1,298,450**
Grand Total			**57,792,107**

Information on Formula Rates:
EAST:
Page 106 lines 10, 13 Depreciation related to station specific fixed assets.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance End of Year	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)	(f)	
			1
			2
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			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant	60,589,123	-70,468
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	60,589,123	-70,468
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)		
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	915,154	8,904,755
38	(341) Structures and Improvements	2,646,569	29,854,752
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators	27,169,284	75,565,804
42	(345) Accessory Electric Equipment	2,462,741	4,134,210
43	(346) Misc. Power Plant Equipment		
44	(347) Asset Retirement Costs for Other Production	1,439,574	2,295,692
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	34,633,322	120,755,213
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	34,633,322	120,755,213

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	65,746,009	91,959
49	(352) Structures and Improvements	142,671,619	19,753,093
50	(353) Station Equipment	1,594,805,263	79,087,705
51	(354) Towers and Fixtures	45,874,959	-7,582,217
52	(355) Poles and Fixtures	778,842,468	54,469,106
53	(356) Overhead Conductors and Devices	362,142,913	31,458,998
54	(357) Underground Conduit	138,678,248	13,943,811
55	(358) Underground Conductors and Devices	530,350,386	59,603,587
56	(359) Roads and Trails	52,682,480	5,814,880
57	(359.1) Asset Retirement Costs for Transmission Plant	652,725	400,461
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	3,712,447,070	257,041,383
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	18,026,676	272,712
61	(361) Structures and Improvements	102,861,308	24,001,148
62	(362) Station Equipment	921,556,152	19,049,188
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	444,505,518	16,106,209
65	(365) Overhead Conductors and Devices	867,323,888	33,850,915
66	(366) Underground Conduit	712,810,359	27,000,041
67	(367) Underground Conductors and Devices	1,595,320,180	74,910,815
68	(368) Line Transformers	663,755,904	8,671,545
69	(369) Services	391,609,531	28,096,839
70	(370) Meters	253,067,818	38,464,290
71	(371) Installations on Customer Premises	11,196,471	542,689
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	38,244,520	2,429,182
74	(374) Asset Retirement Costs for Distribution Plant	9,845,401	13,916,131
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	6,030,123,726	287,311,704
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	11,504,808	2,778,689
87	(390) Structures and Improvements	207,927,820	7,775,939
88	(391) Office Furniture and Equipment	32,932,111	-493,459
89	(392) Transportation Equipment	44,677,971	13,532,398
90	(393) Stores Equipment	2,839,552	633,522
91	(394) Tools, Shop and Garage Equipment	16,374,692	1,954,068
92	(395) Laboratory Equipment	985,987	
93	(396) Power Operated Equipment	230,773	-2,670
94	(397) Communication Equipment	94,457,486	11,111,190
95	(398) Miscellaneous Equipment	3,477,397	310,283
96	SUBTOTAL (Enter Total of lines 86 thru 95)	415,408,597	37,599,960
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	80,782	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	415,489,379	37,599,960
100	TOTAL (Accounts 101 and 106)	10,253,282,620	702,637,792
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	10,253,282,620	702,637,792

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
					3
			60,518,655		4
			60,518,655		5
					6
					7
					8
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					33
					34
					35
					36
		198,701	10,018,610		37
			32,501,321		38
					39
					40
			102,735,088		41
			6,596,951		42
					43
			3,735,266		44
		198,701	155,587,236		45
		198,701	155,587,236		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
		2,767,962	68,605,930		48
336,788		-13,937,308	148,150,616		49
6,307,716		12,714,339	1,680,299,591		50
143,797			38,148,945		51
958,041			832,353,533		52
518,814			393,083,097		53
18,107			152,603,952		54
6,683,003		1,222,969	584,493,939		55
			58,497,360		56
			1,053,186		57
14,966,266		2,767,962	3,957,290,149		58
					59
10,215		-2,767,962	15,521,211		60
454,776			126,407,680		61
1,265,395		8,763	939,348,708		62
					63
2,423,621	-437		458,187,669		64
11,913,855	1,574	-117,392	889,145,130		65
601,093	-83	1,225	739,210,449		66
8,440,668		116,167	1,661,906,494		67
5,163,525	648,330	2,974,780	670,887,034		68
6,021,624	236,867		413,921,613		69
4,757,513			286,774,595		70
233,436		45,187	11,550,911		71
					72
761,544		-45,187	39,866,971		73
			23,761,532		74
42,047,265	886,251	215,581	6,276,489,997		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
		-198,701	14,084,796		86
7,247,841			208,455,918		87
275,676			32,162,976		88
1,863,579			56,346,790		89
32,096			3,440,978		90
192,683			18,136,077		91
317,213			668,774		92
			228,103		93
6,030,564			99,538,112		94
87,959			3,699,721		95
16,047,611		-198,701	436,762,245		96
					97
			80,782		98
16,047,611		-198,701	436,843,027		99
73,061,142	886,251	2,983,543	10,886,729,064		100
					101
					102
					103
73,061,142	886,251	2,983,543	10,886,729,064		104

Schedule Page: 204 Line No.: 5 Column: g

Intangible Plant broken out by Plant Account Between East, West Distribution, and West Transmission.

Plant Account	Company	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
303	East	40,711,178	(70,468)	-	-	-	40,640,710
	West Distribution	18,579,495	-	-	-	-	18,579,495
	West Transmission	1,298,450	-			-	1,298,450
303 Total		**$ 60,589,123**	**$ (70,468)**	**-**	-		**$ 60,518,655**

EAST:

Information on Formula Rates: Page 106 lines 10, 13:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 45 Column: g

Other Production Plant Broken out by Plant Account between East and West Distribution.

Plant Account	Company	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
340	East	-	6,924,323	-	-	-	6,924,323
	West Distribution	915,154	1,980,432	-	-	198,701	3,094,287
340 Total		**915,154**	**8,904,755**	**-**	-	**198,701**	**10,018,610**
341	East	-	13,172,435	-	-	-	13,172,435
	West Distribution	2,646,569	16,682,317	-	-	-	19,328,886
341 Total		**2,646,569**	**29,854,752**	**-**	**-**	**-**	**32,501,321**
344	East	-	31,650,288	-	-	-	31,650,288
	West Distribution	27,169,284	43,915,516	-	-	-	71,084,800
344 Total		**27,169,284**	**75,565,804**	**-**	**-**	**-**	**102,735,088**
345	East	-	1,809,811	-	-	-	1,809,811
	West Distribution	2,462,741	2,324,399	-	-	-	4,787,140
345 Total		**2,462,741**	**4,134,210**	**-**	**-**	**-**	**6,596,951**
346	East	-	-	-	-	-	-
	West Distribution	-	-	-	-	-	-
346 Total		**-**	**-**	**-**	**-**	**-**	**-**
347.1 ARO	East		1,029,702				1,029,702
	West Distribution	1,439,574	1,265,990				2,705,564
347.1 ARO Total		**1,439,574**	**2,295,692**	**-**	**-**	**-**	**3,735,266**
Subtotals	**East**	**-**	**54,586,559**	-	-	-	**54,586,559**
	West Distribution	**34,633,322**	**66,168,654**	-	-	**198,701**	**101,000,677**
Grand Total		**$ 34,633,322**	**$ 120,755,213**	**-**	**-**	**$ 198,701**	**$ 155,587,236**

Schedule Page: 204 Line No.: 49 Column: b

EAST:

Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 50 Column: b

EAST:

Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 58 Column: b

Localized transmission plant at the beginning of the year is : East Transmission is $ 28,961,117.
West Transmission is $ 7,199,998.

EAST:

Information on Formula Rates Page 106 line 23:
Investment base related to station specific fixed assets.

Information on Formula Rates Page 106 line 26:
Investment base as stipulated by contract.

WEST:

Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Schedule Page: 204 Line No.: 58 Column: g

Localized transmission plant at the end of the year is: East Transmission $ 28,961,117
West Transmission $ 7,199,998

Transmission activity broken out by Plant account between East Transmission and West Transmission.

Plant Account	Company	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
350	East Transmission	34,153,366	5	-	-	2,767,962	36,921,333
	West Transmission	31,592,643	91,954	-	-		31,684,597
350 Total		**65,746,009**	**91,959**	**-**		**2,767,962**	**68,605,930**
352	East Transmission	69,538,621	11,507,364	253,640	-	-	80,792,345
	West Transmission	73,132,998	8,245,729	83,148	-	(13,937,308)	67,358,271
352 Total		**142,671,619**	**19,753,093**	**336,788**	**-**	**(13,937,308)**	**148,150,616**
353	East Transmission	1,155,897,546	72,450,598	1,159,675	-	(1,222,968)	1,225,965,501
	West Transmission	438,907,717	6,637,107	5,148,041	-	13,937,307	454,334,090
353 Total		**1,594,805,263**	**79,087,705**	**6,307,716**	**-**	**12,714,339**	**1,680,299,591**
354	East Transmission	36,697,616	(180,885)	108,360	-	-	36,408,371
	West Transmission	9,177,343	(7,401,332)	35,437	-	-	1,740,574
354 Total		**45,874,959**	**(7,582,217)**	**143,797**	**-**	**-**	**38,148,945**
355	East Transmission	357,338,173	4,268,126	483,727	-	-	361,122,572
	West Transmission	421,504,295	50,200,980	474,314	-	-	471,230,961
355 Total		**778,842,468**	**54,469,106**	**958,041**	**-**	**-**	**832,353,533**
356	East Transmission	199,531,735	15,029,472	167,467	-	-	214,393,740
	West Transmission	162,611,178	16,429,526	351,347	-	-	178,689,357
356 Total		**362,142,913**	**31,458,998**	**518,814**	**-**	**-**	**393,083,097**
357	East Transmission	138,378,086	13,942,914	18,107	-	-	152,302,893
	West Transmission	300,162	897	-	-	-	301,059
357 Total		**138,678,248**	**13,943,811**	**18,107**	**-**	**-**	**152,603,952**
358	East Transmission	523,334,483	51,689,989	6,614,327	-	1,222,969	569,633,114
	West Transmission	7,015,903	7,913,598	68,676	-	-	14,860,825
358 Total		**530,350,386**	**59,603,587**	**6,683,003**	**-**	**1,222,969**	**584,493,939**
359	East Transmission	36,218,636	4,081,265	-	-	-	40,299,901
	West Transmission	16,463,844	1,733,615	-	-	-	18,197,459
359 Total		**52,682,480**	**5,814,880**	**-**	**-**	**-**	**58,497,360**
359.1 ARO	East Transmission	651,775	400,461	-	-	-	1,052,236

	West Transmission	950	-	-	-	-	950
359.1 ARO Total		**652,725**	**400,461**	**-**	**-**	**-**	**1,053,186**
Subtotals	**East Transmission**	**2,551,740,037**	**173,189,309**	**8,805,303**	**-**	**2,767,962**	**2,718,892,005**
	West Transmission	**1,160,707,033**	**83,852,074**	**6,160,963**	**-**		**1,238,398,144**
Grand Total		**$ 3,712,447,070**	**$ 257,041,383**	**$ 14,966,266**	**$ -**	**$2,767,962**	**$ 3,957,290,149**

EAST:
Information on Formula Rates Page 106 line 23:
Investment base related to station specific fixed assets.

Information on Formula Rates Page 106 line 26:
Investment base as stipulated by contract.

Information on Formula Rates Page 106.2 line 9:
Investment base as stipulated by contract.

WEST:
Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Information on Formula Rates Page 106.3 line 23:
Investment base as stipulated by contract.

Schedule Page: 204 Line No.: 61 Column: b
EAST:
Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 61 Column: g
EAST:
Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 62 Column: b
EAST:
Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 62 Column: g
EAST:
Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 66 Column: b
EAST:
Information on Formula Rates Page 106.2 line 5:

Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 66 Column: g

EAST:

Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 67 Column: b

EAST:

Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 67 Column: g

EAST:

Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 75 Column: b

EAST:

Information on Formula Rates Page 106 lines 10,13,16,19:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 75 Column: g

Distribution Balances and activity broken out by Plant account between East and West Distribution.

Plant Account	Company	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
360	East	16,605,927	272,712	10,215	-	(2,767,962)	14,100,462
	West Distribution	1,420,749	-	-	-	-	1,420,749
360 Total		**18,026,676**	**272,712**	**10,215**	**-**	**(2,767,962)**	**15,521,211**
361	East	96,178,605	23,802,700	444,935	-	-	119,536,370
	West Distribution	6,682,703	198,448	9,841	-	-	6,871,310
361 Total		**102,861,308**	**24,001,148**	**454,776**	**-**	**-**	**126,407,680**
362	East	832,654,356	12,075,091	1,003,923	-	-	843,725,524
	West Distribution	88,901,796	6,974,097	261,472	-	8,763	95,623,184
362 Total		**921,556,152**	**19,049,188**	**1,265,395**	**-**	**8,763**	**939,348,708**
363	East	-	-	-	-	-	-
	West Distribution			-	-	-	-
363 Total		**-**	**-**	**-**	**-**	**-**	**-**
364	East	365,520,677	11,125,383	1,048,389		-	375,597,671
	West Distribution	78,984,841	4,980,826	1,375,232	(437)	-	82,589,998
364 Total		**444,505,518**	**16,106,209**	**2,423,621**	**(437)**	**-**	**458,187,669**
365	East	705,861,390	20,044,169	8,112,438	1,609	-	717,794,730
	West Distribution	161,462,498	13,806,746	3,801,417	(35)	(117,392)	171,350,400
365 Total		**867,323,888**	**33,850,915**	**11,913,855**	**1,574**	**(117,392)**	**889,145,130**
366	East	641,248,429	21,908,521	54,836		-	663,102,114
	West Distribution	71,561,930	5,091,520	546,257	(83)	1,225	76,108,335
366 Total		**712,810,359**	**27,000,041**	**601,093**	**(83)**	**1,225**	**739,210,449**
367	East	1,434,672,795	65,228,514	6,810,569			1,493,090,740
	West Distribution	160,647,385	9,682,301	1,630,099	-	116,167	168,815,754
367 Total		**1,595,320,180**	**74,910,815**	**8,440,668**	**-**	**116,167**	**1,661,906,494**
368	East	579,825,514	5,957,106	3,573,924	648,330	18,239	582,875,265
	West Distribution	83,930,390	2,714,439	1,589,601	-	2,956,541	88,011,769
368 Total		**663,755,904**	**8,671,545**	**5,163,525**	**648,330**	**2,974,780**	**670,887,034**
369	East	316,280,445	24,463,620	5,460,022	-	-	335,284,043
	West Distribution	75,329,086	3,633,219	561,602	236,867	-	78,637,570
369 Total		**391,609,531**	**28,096,839**	**6,021,624**	**236,867**	**-**	**413,921,613**

370	East	221,928,793	35,409,458	3,517,416	-	-	253,820,835
	West Distribution	31,139,025	3,054,832	1,240,097	-	-	32,953,760
370 Total		**253,067,818**	**38,464,290**	**4,757,513**	**-**	**-**	**286,774,595**
371	East	-	-	-	-	-	-
	West Distribution	11,196,471	542,689	233,436	-	45,187	11,550,911
371 Total		**11,196,471**	**542,689**	**233,436**	**-**	**45,187**	**11,550,911**
373	East	20,068,277	1,511,438	182,229	-	-	21,397,486
	West Distribution	18,176,243	917,744	579,315		(45,187)	18,469,485
373 Total		**38,244,520**	**2,429,182**	**761,544**	**-**	**(45,187)**	**39,866,971**
374.1 ARO	East	9,268,703	7,393,471	-	-		16,662,174
	West Distribution	576,698	6,522,660	-	-	-	7,099,358
374.1 ARO Total		**9,845,401**	**13,916,131**	**-**	**-**	**-**	**23,761,532**
Subtotals	**East**	**5,240,113,911**	**229,192,183**	**30,218,896**	**649,939**	**(2,749,723)**	**5,436,987,414**
	West Distribution	**790,009,815**	**58,119,521**	**11,828,369**	**236,312**	**2,965,304**	**839,502,583**
Grand Total		**$ 6,030,123,726**	**$ 287,311,704**	**$ 42,047,265**	**$ 886,251**	**$ 215,581**	**$ 6,276,489,997**

EAST:
Information on Formula Rates Page 106 lines 10,13,16,19:
Investment base related to station specific fixed assets.

WEST:
Information on Formula Rates:
Page 106.3 line 15 and 19
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 99 Column: b

At the beginning of the year, there is $57,592 in General Plant Account 390, relating to rebranding.

EAST:
Information on Formula Rates Page 106 lines 10,13,16,19:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 99 Column: g

EAST:
Information on Formula Rates Page 106 lines 10,13,16,19:
Investment base related to station specific fixed assets.

At the end of the year, there is $71,462 in General Plant Account 390, relating to rebranding.
East $ 57,592
West - $ 13,870

General Plant Broken out by Plant Account Between East, West Distribution, and West Transmission

Plant Account	Company	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
389	East	9,682,368	2,778,689	-	-	(198,701)	12,262,356
	West Distribution	1,821,608	-	-	-	-	1,821,608
	West Transmission	832	-	-	-	-	832
389 Total		**11,504,808**	**2,778,689**	**-**	**-**	**(198,701)**	**14,084,796**
390	East	183,490,229	5,601,873	7,247,841	-	-	181,844,261
	West Distribution	23,804,798	2,174,066	-	-	-	25,978,864
	West Transmission	632,793	-	-	-	-	632,793
390 Total		**207,927,820**	**7,775,939**	**7,247,841**	**-**	**-**	**208,455,918**
391	East	29,020,879	(747,325)	-	-	-	28,273,554
	West Distribution	3,608,169	253,866	275,676	-	-	3,586,359
	West Transmission	303,063	-	-	-	-	303,063

391 Total		**32,932,111**	**(493,459)**	**275,676**	**-**	**-**	**32,162,976**
392	East	25,006,758	11,570,539	46,282	-	-	36,531,015
	West Distribution	18,752,702	1,961,859	1,795,606	-	-	18,918,955
	West Transmission	918,511	-	21,691	-	-	896,820
392 Total		**44,677,971**	**13,532,398**	**1,863,579**	**-**	**-**	**56,346,790**
393	East	2,132,207	602,614	-	-	-	2,734,821
	West Distribution	707,345	30,908	32,096	-	-	706,157
	West Transmission	-	-	-	-	-	-
393 Total		**2,839,552**	**633,522**	**32,096**	**-**	**-**	**3,440,978**
394	East	9,220,849	1,090,155	103,673	-	-	10,207,331
	West Distribution	4,483,823	406,171	89,010	-	-	4,800,984
	West Transmission	2,670,020	457,742	-	-	-	3,127,762
394 Total		**16,374,692**	**1,954,068**	**192,683**	**-**	**-**	**18,136,077**
395	East	153,628	-	98,595	-	-	55,033
	West Distribution	487,931	-	218,618	-	-	269,313
	West Transmission	344,428	-	-	-	-	344,428
395 Total		**985,987**	**-**	**317,213**	**-**	**-**	**668,774**
396	East	2,670	(2,670)	-	-	-	-
	West Distribution	228,103	-	-	-	-	228,103
	West Transmission	-	-	-	-	-	-
396 Total		**230,773**	**(2,670)**	**-**	**-**	**-**	**228,103**
397	East	47,535,059	8,444,050	4,537,025	-	-	51,442,084
	West Distribution	18,396,102	577,807	1,459,882	-	-	17,514,027
	West Transmission	28,526,325	2,089,333	33,657	-	-	30,582,001
397 Total		**94,457,486**	**11,111,190**	**6,030,564**	**-**	**-**	**99,538,112**
398	East	3,138,919	310,283	65,131	-	-	3,384,071
	West Distribution	249,200	-	22,828	-	-	226,372
	West Transmission	89,278	-	-	-	-	89,278
398 Total		**3,477,397**	**310,283**	**87,959**	**-**	**-**	**3,699,721**
399.1 ARO	East						
	West Distribution	80,782					80,782
	West Transmission						
	399.1 ARO Total	**80,782**	-	-	-	-	**80,782**
Subtotals	**East**	**309,383,566**	**29,648,208**	**12,098,547**	**-**	**(198,701)**	**326,734,526**
	West Distribution	**72,620,563**	**5,404,677**	**3,893,716**	**-**	**-**	**74,131,524**
	West Transmission	**33,485,250**	**2,547,075**	**55,348**	**-**	**-**	**35,976,977**
Grand Total		**$ 415,489,379**	**$37,599,960**	**$16,047,611**	**$ -**	**$ (198,701)**	**$ 436,843,027**

Schedule Page: 204 Line No.: 100 Column: b

EAST:

Information on Formula Rates:

Page 106 line 30 — Amount stipulated per contract.

Page 106.2 lines 1,5 — Amount stipulated per contract.

Page 106 line 35 — Amount stipulated per contract and station specific fixed assets.

Page 106.1 lines 1,8,15,20,27,34 — Amount stipulated per contract and station specific fixed assets.

Page 106.2 line 35 Amount stipulated per contract.

Schedule Page: 204 Line No.: 100 Column: g

EAST:

Information on Formula Rates:

Page 106 line 30 Amount stipulated per contract.

Page 106.2 lines 1,5 Amount stipulated per contract.

Page 106 line 35 Amount stipulated per contract and station specific fixed assets.

Page 106.1 lines 1,8,15,20,27,34 Amount stipulated per contract and station specific fixed assets.

Page 106.2 line 35 Amount stipulated per contract.

Schedule Page: 204 Line No.: 104 Column: b

EAST:

Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Information on Formula Rates:

Page 106 line 30 Amount stipulated per contract.

Page 106.2 lines 1,5,9 Amount stipulated per contract.

Page 106 line 35 Amount stipulated per contract and station specific fixed assets.

Page 106.1 lines 1,8,15,20,27,34 Amount stipulated per contract and station specific fixed assets.

Page 106.2 line 29,35 Amount stipulated per contract and station specific

WEST:

Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Schedule Page: 204 Line No.: 104 Column: g

Total Plant in Service

Company	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
East	8,141,948,692	486,545,791	51,122,746	649,939	(180,462)	8,577,841,214
West Distribution	915,843,195	129,692,852	15,722,085	236,312	3,164,005	1,033,214,279

West Transmission	1,195,490,733	86,399,149	6,216,311	-	-	1,275,673,571
Total	**10,253,282,620**	**702,637,792**	**73,061,142**	**886,251**	**2,983,543**	**10,886,729,064**

EAST:
Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Information on Formula Rates:

Page 106 line 30	Amount stipulated per contract.
Page 106.2 lines 1,5,9	Amount stipulated per contract.
Page 106 line 35	Amount stipulated per contract and station specific fixed assets.
Page 106.1 lines 1,8,15,20,27,34	Amount stipulated per contract and station specific fixed assets.
Page 106.2 line 29,35	Amount stipulated per contract and station specific

WEST:
Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2	Not Applicable				
3					
4					
5					
6					
7					
8					
9					
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12					
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44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Distribution:			
3	Boston - Taber and Harrison Ave	1987	2019	10,226
4	Norfolk - Dean Street	1987-1991	2020	8,475
5	Natick - Mill Street	1987	2019	60,794
6	Yarmouth - Dennis/Yarmouth Station	2008	2019	489,536
7	Parcel F-8-B South Boston - Substation	2009	2019	591,505
8	Freemont Street - Distribution	2015	2022	2,895,553
9	Fulkerson Street - Cambridge - Distribution	2017	2022	7,883,464
10	Dist. Line - Boston	2017	2019	568,709
11	70 Fremont Street - Distribution	2018	2019	527,441
12	Transmission:			
13	Yarmouth - Dennis/Yarmouth Station	2008	2023	492,805
14	Falmouth - Off Currier Road	2015	2021	645,893
15	Parcel F-8 B South Boston - Substation	2009	2019	197,169
16	Freemont Street - Transmission	2015	2022	1,976,737
17	Boston - Hyde Park Substation	2014	2020	11,535,494
18	Future Charlestown S/S - 492 Rutherford Avenue	2016	2024	7,074,168
19	Fulkerson Street - Cambridge - Transmission	2017	2022	5,255,997
20	70 Fremont Street - Transmission	2018	2019	351,682
21	Other Property:			
22	Minor Items (2): Transmission Rights of Way			209,302
23	and Pembroke Street			
24				
25				
26	Land and Land Rights-WEST			
27	53 Russell Street, Hadley, MA	2018	2021	167,361
28				
29				
30				
31				
32				
33				
34				
35	Functionalized: EAST			
36	Distribution 13,035,703			
37	Transmission 27,739,247			
38	Total 40,774,950			
39				
40	Functionalized: WEST			
41	Distribution 167,361			
42	Transmission 0			
43	Total 167,361			
44				
45				
46				
47	Total			40,942,311

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	NSTAR Electric East	
2		
3	East Distribution Plant	
4		
5	Acts of Public Authority - Mass Ave	1,914,609
6	Mass Property Overheads	1,641,867
7	Design Engineering Distribution Substation	1,457,988
8	Carver Station 71 Transformer Replacements	1,550,201
9	Line Convert 344-04 To 13.8KV	1,214,250
10	Communication on Fiber Wire	1,049,406
11	Distribution - Northpoint Parcel North	2,501,224
12	Pole Program	2,414,144
13	Framington Like for Like Replacement	2,390,132
14	Line Upgrade 3-25-25	3,122,936
15	Logan Line Upgrade	2,131,220
16	Mass Ave Like for Like Replacement	9,350,130
17	Minor Cap Improvement & Failure Station	7,841,790
18	Minor Capital Improvements Mass Ave	3,636,481
19	Minor Distribution System Improvement Waltham	2,581,659
20	Distribution System Minor Improvements	1,092,760
21	Minor Station Improvements & Failures	1,639,909
22	Minor System Improvement Somerville	1,058,437
23	Comm Ave Bridge Phase 2 &3	1,846,780
24	North Customer Mass Ave	2,556,461
25	Electric Vehicle Chargers	1,219,282
26	Line Improvements PPC 320-H1	1,862,131
27	Pulte Homes Leg Farms	3,650,396
28	Service to New Customer Station 137	1,422,965
29	SFM Replacements	2,110,827
30	Underground Cable Like for Like Replacement	4,745,322
31	Spare Transformer 90 MVA	1,708,045
32	Station 126 3rd Auto at Hopkinton-Distribution Lane	1,948,395
33	Station 131 East Boston - Distribution	7,938,047
34	Station 315 Electric Ave	14,455,840
35	Station 329 Replace Transformer	4,450,757
36	Station 715 Valley Replace Transformers	5,576,806
37	Station 99 Seafood Way	17,754,516
38	Post Storm Capital Work	14,235,010
39	Tremont Station 713 Transformer Replace	1,226,317
40	URD Cable Cure Injection Upgrades	5,847,172
41	URD Wood Duck Way	1,264,884
42	Waltham Like for Like Replacement	1,198,661
43	TOTAL	470,314,379

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Minor Projects Under $1,000,000	37,127,151
2	East Distribution Plant Subtotal $182,734,908	
3		
4	East General Plant	
5		
6	2018 FAC NE LOB Bldgs	2,823,595
7	Mass East Vehicle Purchases Distribution	2,212,547
8	Small Tools Mass East	1,013,007
9	Minor Projects Under $1,000,000	3,208,912
10	East General Plant Subtotal $9,258,061	
11		
12	East Intangible Plant	
13		
14	Minor Projects Under $1,000,000	139,401
15	East Intangible Plant Subtotal $139,401	
16		
17	East Other Production	
18		
19	Mass Solar Project	23,979,011
20	East Other Production Plant Subtotal $23,979,011	
21		
22	East Transmission Plant	
23		
24	Andrew Square Dewar St	1,129,844
25	Preliminary Engineering Transmission Station	2,074,921
26	Chelsea Substation Project	2,553,183
27	Critical Infrastructure V14 IDS	1,395,592
28	Digital Fault Recorders Replace	1,492,864
29	EMA Battery Monitoring	1,693,971
30	Extend 115 KV Line 114	1,188,172
31	Fulkerson Station 8025 - Transmission Station	1,647,664
32	Line 115 Mid Cape	3,073,442
33	Line 115kV Underground Woburn	38,492,550
34	Line 146 to 502 Walpole to Holbrook	17,814,761
35	Line 345kV Woburn Station 211 to Wakefield	17,106,043
36	Mystic to Chelsea - Transmission Line GB	13,100,527
37	New Line 115kV Sudbury to Hudson GB	12,077,119
38	Rebuild Bourne Substation SRIA	1,440,292
39	Replace Brown Glass Ins Station 446	1,661,618
40	Station 117 Sharon Switching Station GB	12,960,743
41	Station 446 Control House & Line cutovers	2,185,841
42	Station 131 East Boston - Transmission Line	1,512,005
43	TOTAL	470,314,379

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Station 131 East Boston - Transmission Station	4,714,914
2	Station 2 Hawkins GIS & High Side Breakers	1,042,460
3	Station 211 Replace Woburn Transformer	14,853,045
4	Station 250 Install 2nd Transformer Mystic GB	14,714,720
5	Station 250 Upgrade Control House	3,654,828
6	Station 329 Control House & Line cutovers	1,043,938
7	Station 385 Control House & Line cutovers	1,820,779
8	Station 385 Shunt Reactor	4,890,567
9	Station 514 Replace 115KV Breakers	7,024,809
10	Station 65 Medway Substation Project	1,488,784
11	Transmission Line North	2,617,674
12	Transmission Station Improvements North	4,807,063
13	West Roxbury to Needham Reliab GB	4,871,021
14	Minor Projects Under $1,000,000	9,684,207
15	East Transmission Plant Subtotal $211,829,961	
16		
17	NSTAR Electric East Total $427,941,342	
18		
19		
20	NSTAR Electric West Distribution	
21		
22	West Distribution Plant	
23		
24	East Springfield Transformer Replacement	1,700,783
25	Montague Transformer Upgrade	2,612,748
26	Orchard Substation Transformer Addition	1,334,323
27	Replace Gunn Transformer	2,427,865
28	Western Mass Grid Mod Relay Replacement Agawam	1,070,684
29	Western Mass Grid Mod Feeder Relay	1,447,376
30	Minor Projects Under $1,000,000	8,831,015
31	West Distribution Plant Subtotal $19,424,794	
32		
33	West General Plant	
34		
35	2018 West Distribution Buildings and General Plant	1,193,220
36	Minor Projects Under $1,000,000	2,471,399
37	West General Plant Subtotal $3,664,619	
38		
39	West Other Production Plant	
40		
41	Minor Projects Under $1,000,000	47,563
42	West Other Production Plant Subtotal $47,563	
43	TOTAL	470,314,379

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1		
2	West Distribution Total $23,136,976	
3		
4		
5	West Transmission	
6		
7	West Transmission General Plant	
8		
9	Minor Projects Under $1,000,000	88,335
10	West Transmission General Plant Subtotal $88,335	
11		
12	West Transmission Transmission Plant	
13		
14	Transmission Line Projects - 2018	2,980,939
15	Transmission Line 393 ACR	1,457,427
16	Ludlow 115KV Equipment Replace	1,451,269
17	PGA-2 1512 Line Loop	1,221,080
18	PGA-2 Atwater-New Switching Station	1,928,617
19	PGA-2 Buck Pond Substation Modifications	1,733,209
20	PGA-2 New 115kV 1293 Line	1,770,082
21	Minor Projects Under $1,000,000	6,605,103
22	West Transmission Transmission Plant Subtotal $19,147,726	
23		
24	West Transmission Total $ 19,236,061	
25		
26	NSTAR Electric West total $42,373,037	
27		
28		
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41		
42		
43	TOTAL	470,314,379

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	2,750,485,246	2,750,485,246		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	271,328,755	271,328,755		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	4,551,027	4,551,027		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	275,879,782	275,879,782		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	73,051,031	73,051,031		
13	Cost of Removal	25,568,806	25,568,806		
14	Salvage (Credit)	777,128	777,128		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	97,842,709	97,842,709		
16	Other Debit or Cr. Items (Describe, details in footnote):	-18,382,595	-18,382,595		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,910,139,724	2,910,139,724		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production				
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	10,140,974	10,140,974		
25	Transmission	712,168,339	712,168,339		
26	Distribution	2,069,226,068	2,069,226,068		
27	Regional Transmission and Market Operation				
28	General	118,604,343	118,604,343		
29	TOTAL (Enter Total of lines 20 thru 28)	2,910,139,724	2,910,139,724		

Schedule Page: 219 Line No.: 12 Column: c

Book Cost of Plant Retired:

Retirements from reserves	$73,051,031
Miscellaneous reserve retirements	10,111
Total retirements (ties to page 207)	$73,061,142

Schedule Page: 219 Line No.: 16 Column: c

Other debit or (credit) items

Sundry billing	$ 102,645
Journal entries	(153,318)
Transfers and adjustments	1,989,195
ARO activity	937,437
Total removal work in progress	(21,258,555)
Total other debits or credit items	$ (18,382,595)

Schedule Page: 219 Line No.: 19 Column: c

Information on Formula Rates:

Page 106.2 line 1 Depreciation amount stipulated by contract.

Schedule Page: 219 Line No.: 24 Column: c

Company	Function	Balance
East	Other	421,802
West Distribution	Other	9,719,172
Total		**$ 10,140,974**

Schedule Page: 219 Line No.: 25 Column: c

Company	Function	Balance
East	Transmission	617,843,746
West Transmission	Transmission	94,324,594
Total		**$ 712,168,339**

EAST:

Information on Formula Rates:

Page 106.2 line 5 Depreciation amount stipulated by contract.

WEST:

Information on Formula Rates:

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II. Reference Page 106.3 line 9.

Schedule Page: 219 Line No.: 26 Column: c

Company	Function	Balance
East	Distribution	1,834,262,908
West Distribution	Distribution	234,963,160
Total		**$ 2,069,226,068**

EAST:

Information on Formula Rates:

Page 106 lines 10,13 Depreciation related to station specific fixed assets.

Page 106.2 line 5 Depreciation related to station specific fixed assets.

Page 106.2 line 1 Depreciation amount stipulated by contract.

Schedule Page: 219 Line No.: 28 Column: c

Company	Function	Balance
East	General	85,222,756
West Distribution	General	24,195,841
West Transmission	General	9,185,746
Total		**$ 118,604,343**

EAST:

Information on Formula Rates:

Page 106 lines 10,13 Depreciation related to station specific fixed assets.

Page 106.2 line 1 Depreciation amount stipulated by contract.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Connecticut Yankee Atomic Power Company			
2	Common Stock			469,654
3	Equity and Dividends			-33,870
4	Subtotal			435,784
5				
6	Maine Yankee Atomic Power Company			
7	Common Stock			135,307
8	Equity and Dividends			26,361
9	Subtotal			161,668
10	Yankee Atomic Electric Company (Massachusetts)			
11	Common Stock			161,070
12	Equity and Dividends			156,798
13	Subtotal			317,868
14				
15	Harbor Electric Energy Company			
16	Common Stock			1,000
17	Capital Contribution			4,400,000
18	Undistributed subsidiary earnings			-5,430,671
19	Subtotal			-1,029,671
20				
21	New England Hydro-Transmission Electric Company			
22	Common Stock			68,719
23	Capital Contribution			4,520,245
24	Undistributed subsidiary earnings			1,471,168
25	Subtotal			6,060,132
26				
27	New England Hydro-Transmission Corporation			
28	Common Stock			1,446
29	Capital Contribution			521,105
30	Undistributed subsidiary earnings			323,173
31	Subtotal			845,724
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	6,791,505

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
	-1	469,655		2
19,814		-14,056		3
19,814	-1	455,599		4
				5
				6
		135,307		7
7,331		33,692		8
7,331		168,999		9
				10
		161,070		11
-4,742		152,056		12
-4,742		313,126		13
				14
				15
		1,000		16
	13,500,000	17,900,000		17
-4,963,149		-10,393,820		18
-4,963,149	13,500,000	7,507,180		19
				20
				21
		68,719		22
		4,520,245		23
642,557		2,113,725		24
642,557		6,702,689		25
				26
				27
		1,446		28
		521,105		29
31,336		354,509		30
31,336		877,060		31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
-4,266,853	13,499,999	16,024,653		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)			
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)	10,762,392	15,734,279	Electric
9	Distribution Plant (Estimated)	38,769,138	45,959,392	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	49,531,530	61,693,671	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	391,487	45,571	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	49,923,017	61,739,242	

FOOTNOTE DATA

Schedule Page: 227 Line No.: 8 Column: b

Transmission Inventory:
East $8,146,367
West 2,616,025
Total $10,762,392

Calculated per company records as stipulated per contract.
Reference Page 106 line 1.

Schedule Page: 227 Line No.: 8 Column: c

EAST-Calculated per company records as stipulated per contract.
Reference Page 106 line 1.

Transmission Inventory:
East $13,131,552
West 2,602,727
Total $15,734,279

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		2019	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2020		2021		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
								1
								2
								3
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								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		2019	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year		50,391,921		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10	Massachusetts Renewable		65,594,115		
11	Energy Certificate				
12					
13					
14					
15	Total		65,594,115		
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23	Massachusetts Renewable		50,391,921		
24	Energy Certificate				
25					
26					
27					
28	Total		50,391,921		
29	Balance-End of Year		65,594,115		
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2020		2021		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
							50,391,921	1
								2
								3
								4
								5
								6
								7
								8
								9
							65,594,115	10
								11
								12
								13
								14
							65,594,115	15
								16
								17
								18
								19
								20
								21
								22
							50,391,921	23
								24
								25
								26
								27
							50,391,921	28
							65,594,115	29
								30
								31
								32
								33
								34
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								46

FOOTNOTE DATA

Schedule Page: 229 Line No.: 29 Column: c

Represents the value of Renewable Energy Certificates (RECs) that NSTAR Electric Company uses to meet the Commonwealth of Massachusetts' Renewable Portfolio Standards requirements. These RECs are recorded in Account 158.3.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Not Applicable					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	Not Applicable					
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	Atlantic Link	2,433	186	2,433	186
3	Bay State Wind	3,858	186	3,602	186
4	Brayton Point Wind	124	186		
5	Cabot Power	27,099	186	9,229	186
6	Canal	3,221	186		
7	Clean Energy Connect	2,042	186	3,233	186
8	Cross Rd	618	186	124	186
9	Falmouth Energy Storage	757	186	757	186
10	MacDill Solar	11,231	186	10,294	186
11	Maine Green Line	747	186	747	186
12	Maine Power Express	121,990	186	123,042	186
13	Northeast Renewable Link	8,499	186	8,499	186
14	Revolutionary Wind	263	186		
15	UMASS	9,434	186		
16	Vineyard Wind	1,141	186	3,087	186
17	Vineyard Wind 2	371	186	124	186
18					
19					
20					
21	**Generation Studies**				
22					
23	None				
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Fuel litigation costs	200,527	4,773			205,300
2						
3	Connecticut Yankee Shutdown Costs:					
4	On 12/4/96, the Board decided to cease					
5	operations at the nuclear power plant. This					
6	is NSTAR Electric's share of estimated costs					
7	for plant closure and fuel storage obligations.	1,037,020	15,832	253/555	43,816	1,009,036
8						
9	Massachusetts Yankee Shutdown Costs:					
10	On 2/26/92, the Board decided to cease					
11	operations at the nuclear power plant. This					
12	is NSTAR Electric's share of estimated costs					
13	for plant closure and fuel storage obligations.	16,873	17,843	253/555	9,340	25,376
14						
15	Maine Yankee Shutdown Costs:					
16	On 8/6/97, the Board decided to cease					
17	operations at the nuclear power plant. This					
18	is NSTAR Electric's share of estimated costs					
19	for plant closure and fuel storage obligations.	411,472	2,865	253/555	21,728	392,609
20						
21	Income tax regulatory liability ASC 740					
22	(elements amortized over various periods)	117,390,939	6,840,940	283/407.3	9,150,129	115,081,750
23						
24	Asset Retirement Obligation ASC 410	39,005,483	3,150,381			42,155,864
25						
26	NSTAR Goodwill - 40 year amortization	313,577,627		407.3	14,472,829	299,104,798
27	D.P.U. 99-19					
28						
29	Prepaid Pension	401,805,851	57,422,414			459,228,265
30						
31	Pension and PBOP ASC 715	158,637,879	106,025	228.3/926	74,534,899	84,209,005
32						
33	Basic Service Reconciliation:					
34	D.P.U. 06-40, 97-120					
35	The Company defers the cost to					
36	provide basic service to customers compared					
37	to amounts billed to customers, plus carrying					
38	charge.	28,241,837	4,415,172	555	32,657,009	
39						
40	Residential Assistance Adjustment Clause:					
41	This mechanism allows for the recovery of					
42	costs related to low income Residential					
43	Assistance D.P.U. 12-126, 01-106B, 04-106	20,700,578	17,692,300	904/407.4	21,964,965	16,427,913
44	TOTAL	1,504,849,772	509,187,395		585,701,808	1,428,335,359

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1						
2	AFUDC (D.P.U. method amortized over 42 years)	2,410,998		407.3	270,900	2,140,098
3						
4	NSTAR Green implementation costs	26,059		407.4	26,059	
5	D.P.U. 07-64-A					
6						
7	Energy contract derivative	1,232,421		244	1,109,315	123,106
8						
9	Net metering D.P.U. 12-116, 09-74	16,949,221	187,902,005	Footnote	204,851,226	
10						
11	Attorney General consultant expenses	691,751	219,341	407.3	676,732	234,360
12	D.P.U. 11-90, 10-70					
13						
14	Deferred storm restoration costs	127,037,412	14,278,722	407.3	21,524,757	119,791,377
15	D.P.U. 96-23, 05-85					
16						
17	Recoverable storm costs 2011 D.P.U. 13-52	8,192,148	196,162	407.3	8,388,310	
18						
19	Deferred storm restoration costs					
20	D.P.U. 06-55	11,358,509	201,875	407.3	6,323,279	5,237,105
21						
22	Deferred storm restoration costs					
23	D.P.U. 17-05		94,835,431			94,835,431
24						
25	Long term renewable contract adjustment					
26	D.P.U. 11-05, 11-06, 11-07					
27	This mechanism allows for the recovery of					
28	costs associated with Long-Term Renewable					
29	Contracts that are in place to satisfy the					
30	requirements of the Green Communities					
31	Act	37,890,928	1,257,394	555	24,381,210	14,767,112
32						
33	Energy Efficiency Reconciliation	151,722,648	79,326,854	Footnote	142,702,915	88,346,587
34	D.P.U. 13-121, 89-260					
35						
36	Uncollectibles Associated with Basic Service	1,847,399	7,035,783	Footnote	8,883,182	
37	D.P.U. 03-88A, 03-88A-F					
38						
39	Resiliency Tree Work D.P.U. 17-05	2,983,635	22,407,585			25,391,220
40						
41	Merger Costs D.P.U. 17-05	30,523,730		407.3	2,500,755	28,022,975
42	(10 year amortization)					
43						
44	TOTAL	1,504,849,772	509,187,395		585,701,808	1,428,335,359

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Customer Hardship D.P.U. 17-05	23,500,334		904	4,324,728	19,175,606
2	(5 year amortization)					
3						
4	Rate Case Costs D.P.U. 17-05	4,697,429		407.3	861,195	3,836,234
5	(5 year amortization)					
6						
7	CPSL Costs D.P.U. 05-85	29,080	18,677	182.3	47,757	
8						
9	Revenue Decoupling D.P.U. 17-05	2,087,597	3,502,563	407.4	5,590,160	
10						
11	Federal Tax Rate Reduction	384,613		190	384,613	
12						
13	Other Benefit Deferrals (ASC 715)	257,774	727,016			984,790
14						
15	Solar Program D.P.U. 09-05, 16-105		6,404,967			6,404,967
16						
17	Grid Modernization Plan D.P.U. 15-122		197,619			197,619
18						
19	Smart Solar D.P.U. 17-140		1,006,856			1,006,856
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	1,504,849,772	509,187,395		585,701,808	1,428,335,359

FOOTNOTE DATA

Schedule Page: 232 Line No.: 22 Column: f

NSTAR Electric East Distribution	$ 82,644,846
NSTAR Electric West Distribution	32,436,904
Total	$115,081,750

Schedule Page: 232 Line No.: 29 Column: f

NSTAR Electric East Distribution	$459,228,265

Schedule Page: 232 Line No.: 31 Column: f

NSTAR Electric West Distribution	$85,796,408
NSTAR Electric East Distribution	(1,587,403)
Total	$84,2009,005

Schedule Page: 232.1 Line No.: 9 Column: d

Account:	Amount:
456	$188,724,348
555	14,985,094
407.4	1,035,634
431	106,150
Total	$204,851,226

Schedule Page: 232.1 Line No.: 33 Column: d

Account:	Amount:
447	$ 70,016,520
908	52,675,882
242	13,260,320
142	6,750,193
Total	$142,702,915

Schedule Page: 232.1 Line No.: 36 Column: d

Account:	Amount:
904	$7,208,685
186	1,669,359
431	5,138
Total	$8,883,182

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Deferred basic service bad debt	7,504,709	14,158,494	144/904	13,802,778	7,860,425
2	costs					
3						
4	Reimbursable substation costs	6,565,711		565	471,788	6,093,923
5						
6	Unamortized revolver fees	2,147,548	1,090,730	428/431	1,244,495	1,993,783
7						
8	Deferred insurance costs	18,583,149	3,640,026			22,223,175
9						
10	Allowance for hardship accounts	21,925,521	9,801,788	144/904	4,279,003	27,448,306
11						
12	Real estate transactions	541,869	18,834			560,703
13						
14	Cape Wind transmission study	-168,800	168,800			
15						
16	EESCO Long Term Receivable	5,452,453				5,452,453
17						
18	Mutual aid storm work	1,564,798		588	1,564,798	
19						
20	Massachusetts solar	551,072	455,784	182.3	1,006,856	
21						
22	Deferred property tax Increases	11,328,627				11,328,627
23						
24	Facilities impairment deferral	474,767				474,767
25						
26	Farm discount deferral		549,941			549,941
27						
28	Environmental reserve		4,367,406			4,367,406
29						
30	Minor items	337,967	1,725,233	143/142	394,538	1,668,662
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	76,809,391				90,022,171

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2		398,218,961	462,181,372
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	398,218,961	462,181,372
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	398,218,961	462,181,372

Notes

Schedule Page: 234 Line No.: 2 Column: b

EAST	WEST	TOTAL
305,411,665	92,807,296	398,218,961

WEST:

At the beginning of the year, the total balance of Accumulated Deferred Income Taxes in Account 190 includes a transmission related component of $43,444,604. In addition, Account 254 includes a transmission related component of ($1,058,337) transferred from this account as a result of the Federal Income Tax Act.

At the beginning of the year, the total balance of Accumulated Deferred Income Taxes in Account 190 (Reserve for Disputed Transactions) includes a transmission related component of $0.

Information on Formula Rates:

Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.
Reference Page 106, Line 1.

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.
Reference Page 106, Line 1.

Schedule Page: 234 Line No.: 2 Column: c

EAST	WEST	TOTAL
359,927,916	102,253,456	462,181,372

EAST:

	Amount	Business Unit
Post employment benefits accrued	$23,812,128	All (Labor)
Workers Compensation	2,995,474	All (Labor)
Workers Compensation gross up payable	4,801,981	All (Labor)
Performance Reward Program	1,544,052	All (Labor)
Self insurance reserves	1,828,932	All (Plant)
Allowance for uncollectible accounts	13,134,705	Distribution
Hazardous waste reserves	3,737,290	All (Plant)
Pension expense	35,681,234	All (Labor)
Pension adjustment mechanism	15,697,526	Retail Adjuster Clause
Deferred default service	1,234,425	Retail Adjuster Clause
Deferred Net Metering Costs	6,183,796	Distribution
Deferred Energy Efficiency	6,231,740	Retail Adjuster Clause
Storm Contingency Fund	1,408,432	Distribution
Deferred transmission revenues	24,310,434	Retail Adjuster Clause
ASC 740 deferred income taxes (FAS109)	212,753,695	All (Plant)
Other items	4,572,072	All (Plant)
Total	$359,927,916	

Information on Formula Rates page 106.2 line 1,35:
Amount as stipulated per contract.

WEST:

	Beginning Balance	Activity	Ending Balance
Account 190 ASC 740 Gross-Up (FAS 109)	74,170,428	2,003,515	76,173,943
Account 190 ASC 740 ITC (FAS 109)	2,117,016	3,498,239	5,615,255
Account 190 Comprehensive Income	860,075	(192,672)	667,403
Account 190 Asset Retirement Obligations	1,633,508	2,285,139	3,918,647
Bad Debts	3,867,260	797,023	4,664,283
Employee Benefits	8,102,124	(295,697)	7,806,427
Regulatory Deferrals	1,619,099	2,390,483	4,009,582
Other	437,786	(1,039,870)	(602,084)
Sub-total ARO's	15,659,777	4,137,078	19,796,855
TOTAL 190	92,807,296	9,446,160	102,253,456

At the beginning of the year, the total balance of Accumulated Deferred Income Taxes in Account 190 includes a transmission related component of $43,444,604.

At the beginning of the year, the total balance of Accumulated Deferred Income Taxes in Account 190 (Reserve for Disputed Transactions) includes a transmission related component of $0.

At the end of the year, the total balance of Accumulated Deferred Income Taxes in Account 190 includes a transmission related component of $41,969,598.

At the end of the year, the total balance of Accumulated Deferred Income Taxes in Account 190480 (Reserve for Disputed Transactions) includes a transmission related component of $0.

FOOTNOTE DATA

Information on Formula Rates:
Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.
Reference Page 106, Line 1.

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.
Reference Page 106, Line 1.

Schedule Page: 234 Line No.: 18 Column: b

Information on Formula Rates: See line 1 for additional information:
Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II. Reference Page 106.3, Line 9.

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.
Reference Page 106.3, Line 9.

Schedule Page: 234 Line No.: 18 Column: c

Information on Formula Rates: See line 1 for additional information:
Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II. Reference Page 106.3, Line 9.

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.
Reference Page 106.3, Line 9.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201:			
2	Common Stock	200	1.00	
3				
4				
5				
6				
7	Total Common	200	1.00	
8				
9				
10	Account 204:			
11	Cumulative preferred NSTAR Electric East:			
12	4.25% series	180,000	100.00	103.63
13	4.78% series	250,000	100.00	102.80
14				
15				
16				
17	Authorized and unissued	2,460,000		
18				
19	Total Preferred	2,890,000		
20				
21				
22				
23				
24				
25				
26				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
200	200					2
						3
						4
						5
						6
200	200					7
						8
						9
						10
						11
180,000	18,000,000					12
250,000	25,000,000					13
						14
						15
						16
						17
						18
430,000	43,000,000					19
						20
						21
						22
						23
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						27
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						29
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						42

FOOTNOTE DATA

Schedule Page: 250 Line No.: 19 Column: f

Total is 100% Eastern Massachusetts.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Donations Received from Stockholders (Account 208)	
2	None	
3		
4		
5	Reduction in Par or Stated Value of Capital Stock (Account 209)	
6	None	
7		
8		
9	Gain on Resale or Cancellation of Reacquired Capital Stock	
10	(Account 210)	
11	None	
12		
13		
14	Miscellaneous Paid-In Capital (Account 211)	
15		
16		
17	Beginning balance	2,673,237,858
18	Capital contribution from Parent Company	130,000,000
19	WEST-Common stock balance reclassifed on 2018 merger	10,866,225
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
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38		
39		
40	TOTAL	2,814,104,083

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Not Applicable	
2		
3		
4		
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21		
22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 224 (NSTAR Electric East)		
2	2006 $200M 5.75% Debentures	200,000,000	2,180,549
3			17,719,179
4			2,114,000 D
5	2010 $300M 5.50% Debentures	300,000,000	3,123,342
6			4,806,000 D
7	2012 $400M 2.375% Debentures	400,000,000	3,178,574
8			1,096,000 D
9	2014 $300M 4.4% Debentures	300,000,000	3,064,448
10			2,073,000 D
11	2016 $250M 2.7% Debentures	250,000,000	2,140,898
12			870,000 D
13	2015 $250M 3.25% Debentures	250,000,000	2,129,952
14			1,202,500 D
15	2017 $700M 3.20% Debentures	700,000,000	6,340,099
16			266,000 D
17			-4,105,500 P
18	Senior Notes (Nstar Electric West)		
19	2004 Series B, 5.90% Fixed Rate	50,000,000	546,179
20			173,500 D
21	2007 Series D, 6.70% Fixed Rate	40,000,000	501,464
22			189,200 D
23	2010 Series E, 5.10% Fixed Rate	95,000,000	991,276
24			336,300 P
25	2011 Series F, 3.50% Fixed Rate	250,000,000	2,247,325
26			908,000 D
27			-9,571,500 P
28	2013 Series G, 3.88% Fixed Rate	80,000,000	450,757
29			
30	2016 Series H, 2.75% Fixed Rate	50,000,000	308,911
31	Column (c): expenses listed first, followed by call premiums,		
32	then discount (D)/premium (P) for each obligation		
33	TOTAL	2,965,000,000	45,280,453

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Additional Footnotes.		
2			
3			
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28			
29			
30			
31			
32			
33	TOTAL	2,965,000,000	45,280,453

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
03/16/2006	03/15/2036	03/2006	03/2036	200,000,000	11,500,000	2
						3
						4
03/16/2010	03/15/2040	03/2010	03/2040	300,000,000	16,500,000	5
						6
10/15/2012	10/15/2022	10/2012	10/2022	400,000,000	9,500,000	7
						8
03/07/2014	03/01/2044	03/2014	03/2044	300,000,000	13,200,000	9
						10
05/26/2016	06/01/2026	05/2016	06/2026	250,000,000	6,750,000	11
						12
11/18/2015	11/15/2025	11/2015	11/2025	250,000,000	8,125,000	13
						14
05/15/2017	05/15/2027	05/2017	05/2027	700,000,000	22,400,000	15
						16
						17
						18
09/23/2004	09/15/2034	10/2004	09/2034	50,000,000	2,950,000	19
						20
08/17/2007	08/15/2037	08/2007	08/2037	40,000,000	2,680,000	21
						22
03/08/2010	03/01/2020	03/2010	02/2020	95,000,000	4,845,000	23
						24
09/16/2011	09/15/2021	09/2011	08/2021	250,000,000	8,750,000	25
						26
						27
11/15/2013	11/15/2023	11/2013	11/2023	80,000,000	3,104,000	28
						29
06/23/2016	06/15/2026	06/2016	06/2026	50,000,000	1,375,000	30
						31
						32
				2,965,000,000	111,679,000	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
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						30
						31
						32
				2,965,000,000	111,679,000	33

FOOTNOTE DATA

Schedule Page: 256.1 Line No.: 1 Column: a

Excluded from the total interest for the year is $3,569 for interest related to other comprehensive income.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	383,090,152
2		
3		
4	Taxable Income Not Reported on Books	
5	Contributions in aid of construction - East	24,096,521
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See footnote	651,827,353
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See footnote	40,759,325
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See footnote	547,183,176
21		
22	Taxable Income - line 1 + line 5 +line 10 - line 15 -line 20	471,071,525
23	State Income taxes - East	-29,784,460
24	State Tax - Prior Year Adjustment -East	773,900
25		
26		
27	Federal Tax Net Income	442,060,965
28	Show Computation of Tax:	
29		
30	Estimated federal tax payable @21%	92,832,803
31		
32		
33		
34		
35		
36		
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43		
44		

Schedule Page: 261 Line No.: 1 Column: b

	EAST	WEST	TOTAL
Net Income	315,658,727	67,431,425	383,090,152

Schedule Page: 261 Line No.: 10 Column: b

	EAST	WEST	TOTAL
Deductions on books not on the return	609,169,015	42,658,338	651,827,353

EAST:

Deductions on books not on the return	
Compensation expense	5,651,729
Bond redemption amortization	606,648
Book depreciation	222,211,672
Capital leases	4,794,089
Capitalized interest	9,649,630
Deferred cost of electricity	119,450,670
Federal income tax expense	84,552,897
Goodwill amortization	14,472,829
Hazardous waste disposal costs	3,699,966
Merger costs	1,085,662
Energy efficiency	70,688,946
Salvage	324,969
State income taxes	34,862,360
Equity earnings exclusion	4,963,149
Deferred net metering costs	25,988,861
Vehicle amortization	1,396,215
Self insurance	2,472,384
Lobbying expense	593,678
Other items	1,702,661
	609,169,015

WEST:

Income on books not on the return	
Employee compensation and benfits	11,626,549
Current and deferred federal and state income taxes	29,720,122
Bad debt expense	905,103

Other	406,564
Total	42,658,338

Schedule Page: 261 Line No.: 15 Column: b

	EAST	WEST	TOTAL
Income on books not on the return	40,759,325	0	40,759,325

Income on books not on the return

Amortization of ITC	1,151,351
Contribution in aid of construction	3,172,189
Pension and post retirement costs	36,225,635
Life insurance	210,150
	40,759,325

Schedule Page: 261 Line No.: 20 Column: b

	EAST	WEST	TOTAL
Deductions on books not on the return	495,533,393	51,649,783	547,183,176

EAST:

Deductions on return not on books

Tax depreciation	208,913,985
Bonus depreciation	102,276,593
Repairs expense	17,130,701
AFUDC Debt	781,919
AFUDC Equity	14,920,641
Compensation expense	7,058,516
Cost of removal	29,113,467
Bond redemption amortization	85,472
Loss on asset retirement	18,014,731
Mixed service costs	15,410,511
Pension and PBOP payments	4,309,758
Municipal taxes	1,544,657
Storm costs	74,241,935
Uncollectible accounts	694,900
Accrued Maint/Warranty Reserves	153,709
Other items	881,898
	495,533,393

WEST:

Income on books not on the return

Book/Tax Property Differences	49,606,046
Amortization/Deferral of Regulatory Assets/Liabilities	2,043,737
Total	51,649,783

Schedule Page: 261 Line No.: 22 Column: b

	EAST	WEST	TOTAL
Taxable Income	412,631,545	58,439,980	471,071,525

Schedule Page: 261 Line No.: 23 Column: b

EAST:

Taxable income	412,631,545
State adjustment for bonus depreciation	(40,325,797)
Taxable income for state	372,305,748
State Tax @ 8%	- 29,784,460

Schedule Page: 261 Line No.: 27 Column: b

	EAST	WEST	TOTAL
Federal Taxable Income	383,620,985	58,439,980	442,060,965

This company is a member of an affiliated group, Eversource Energy and Subsidiaries, which will file a 2018 consolidated federal Income Tax return on or before October 15, 2019.

Members of the group are:
Eversource Energy
The Connecticut Light and Power Company
The Connecticut Steam Company
Electric Power, Inc.
NGS Sub, Inc.
Harbor Electric Energy Company
Hopkinton LNG Corp.
HWP Company
North Atlantic Energy Corporation
North Atlantic Energy Service Corporation
Northeast Generation Services Company
Northeast Nuclear Energy Company
Eversource Energy Service Company
NSTAR Electric Company
NSTAR Gas Company
NU Enterprises, Inc.
Eversource Energy Transmission Ventures, Inc.
The Nutmeg Power Company
Properties, Inc.
Public Service Company of New Hampshire
Renewable Properties, Inc.
The Rocky River Realty Company
Yankee Energy System, Inc.
Yankee Gas Services Company
Eversource Holdco Corporation
Eversource Water Ventures, Inc.

FOOTNOTE DATA

Eversource Aquarion Holdings, Inc.
Aquarion Company
Homeowner Safety Valve Company
Aquarion Water Company
Aquarion Water Company of New Hampshire
Aquarion Water Capital of Massachusetts, Inc.
Aquarion Water Company of Massachusetts, Inc.
Aquarion Water Company of Connecticut

The above entities are parties to a tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate Company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized.

Schedule Page: 261 Line No.: 30 Column: b

	EAST	WEST	TOTAL
Estimated Federal tax payable @21%	80,560,407	12,272,396	92,832,803

WEST:

Estimated Federal Tax @21%	**12,272,396**
Tax Billed to Affiliate for Stranded Cost	**287,436**
Prior Year Taxes	**2,713,889**
Miscellaneous Credit Adjustment	**(10,997)**
Total	**15,262,724**

Federal Income Tax	**$16,792,446**
Federal Income Tax - Other Income/Deductions (Page 117,line 53)	**($1,529,722)**
Total	**$15,262,724**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.)
Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	NSTAR ELECTRIC (EAST)					
2	FEDERAL					
3	Unemployment 2017	28,575			28,575	
4	Unemployment 2018			28,972	2,344	
5	FICA 2017	578,173			578,173	
6	FICA 2018			4,438,064	3,838,342	
7	Income	4,863,436		49,898,386	81,354,454	
8	Medicare 2017	135,218			135,218	
9	Medicare 2018			1,238,507	1,098,250	
10	Subtotal	5,605,402		55,603,929	87,035,356	
11						
12	STATE OF CONNECTICUT					
13	Insurance Premium Excise			160,212	160,212	
14	Unemployment 2018			62,862	62,862	
15	Subtotal			223,074	223,074	
16						
17	COMMONWEALTH OF					
18	MASSACHUSETTS					
19	Unemployment 2017	65,400			65,400	
20	Unemployment 2018			393,097	176,710	
21	Income		7,420,027	26,535,596	25,424,650	
22	Mass Sales Tax			215,535	171,225	
23	Universal Health 2017	17,148			17,148	
24	Universal Health 2018			43,908	20,257	
25	Subtotal	82,548	7,420,027	27,188,136	25,875,390	
26						
27	LOCAL MASSACHUSETTS					
28	Property 2017	4,642,148			4,642,148	
29	Property 2018			138,700,837	135,581,739	
30	Subtotal	4,642,148		138,700,837	140,223,887	
31						
32	STATE OF NEW					
33	HAMPSHIRE					
34	Unemployment 2018			8,652	8,652	
35	Subtotal			8,652	8,652	
36						
37	DISTRICT OF COLUMBIA					
38	Unemployment 2018			50	50	
39	Subtotal			50	50	
40						
41	TOTAL	12,127,449	7,889,769	274,255,895	309,573,206	-25,940

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.)
Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	NSTAR ELECTRIC (WEST)					
2	FEDERAL					
3	Unemployment 2017	7,355			7,355	
4	Unemployment 2018			6,170	899	
5	FICA 2017	127,464			127,464	
6	FICA 2018			879,917	740,938	
7	Highway			-2,720	-2,720	
8	Income	1,033,757		1,820,190	5,505,269	-25,940
9	Medicare 2017	29,810			29,810	
10	Medicare 2018			235,165	202,662	
11	Subtotal	1,198,386		2,938,722	6,611,677	-25,940
12						
13	STATE OF CONNECTICUT					
14	Unemployment 2018			15,598	15,598	
15	Insurance Premium Excise			35,121	35,121	
16	Corporation Business			-8,220	-8,220	
17	Subtotal			42,499	42,499	
18						
19	COMMONWEALTH OF					
20	MASSACHUSETTS					
21	Unemployment 2017	14,535			14,535	
22	Unemployment 2018			30,604	10,536	
23	Income	579,886		1,614,356	3,609,863	
24	Corporate Excise			-435,000	-435,000	
25	Universal Health 2017	4,544			4,544	
26	Universal Health 2018			9,009	2,075	
27	Subtotal	598,965		1,218,969	3,206,553	
28						
29	LOCAL MASSACHUSETTS					
30	Property 2017		469,742	469,742		
31	Property 2018			47,859,125	46,343,908	
32	Subtotal		469,742	48,328,867	46,343,908	
33						
34	STATE OF NEW					
35	HAMPSHIRE					
36	Unemployment 2018			2,147	2,147	
37	Subtotal			2,147	2,147	
38	DISTRICT OF COLUMBIA					
39	Unemployment 2018			13	13	
40	Subtotal			13	13	
41	TOTAL	12,127,449	7,889,769	274,255,895	309,573,206	-25,940

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
						3
26,628		28,972				4
						5
599,722		4,438,064				6
	26,592,632	59,726,819			-9,828,433	7
						8
140,257		1,238,507				9
766,607	26,592,632	65,432,362			-9,828,433	10
						11
						12
		160,212				13
		62,862				14
		223,074				15
						16
						17
						18
						19
216,387		393,097				20
	6,309,081	26,298,359			237,237	21
44,310		215,535				22
						23
23,651		43,908				24
284,348	6,309,081	26,950,899			237,237	25
						26
						27
						28
3,119,098		138,451,501			249,337	29
3,119,098		138,451,501			249,337	30
						31
						32
						33
		8,652				34
		8,652				35
						36
						37
		50				38
		50				39
						40
5,889,025	36,942,716	298,994,681			-24,738,786	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
						3
5,271		6,170				4
						5
138,979		879,916				6
		-2,720				7
	2,625,382	16,792,446			-14,972,256	8
						9
32,503		235,165				10
176,753	2,625,382	17,910,977			-14,972,256	11
						12
						13
		15,598				14
		35,121				15
		-8,220				16
		42,499				17
						18
						19
						20
						21
20,068		30,604				22
	1,415,621	2,259,530			-645,174	23
		-435,000				24
						25
6,934		9,009				26
27,002	1,415,621	1,864,143			-645,174	27
						28
						29
		469,742				30
1,515,217		47,638,622			220,503	31
1,515,217		48,108,364			220,503	32
						33
						34
						35
		2,147				36
		2,147				37
						38
		13				39
		13				40
5,889,025	36,942,716	298,994,681			-24,738,786	41

Schedule Page: 262 Line No.: 7 Column: l

Total includes $218,120 for non-operating taxes account 409.2; and $9,610,313 for solar tax credits reclassed from account 236 to account 255 (Accumulated Deferred Investment Tax Credits).

Schedule Page: 262 Line No.: 21 Column: l

State of Massachusetts income taxes apportioned to other income account 409.2.

Schedule Page: 262 Line No.: 29 Column: i

Information on Formula Rates:

Page 106 lines 26, 30, 35	Town specific local taxes.
Page 106.1 lines 1, 8, 15, 20, 27,34	Town specific local taxes.
Page 106.2 line 29	Town specific local taxes.
Page 106.2 lines 1, 5	Amount stipulated per contract.

Schedule Page: 262 Line No.: 29 Column: l

Non-utility real estate and personal property tax assigned to account 408.2.

Schedule Page: 262.1 Line No.: 4 Column: i

Federal unemployment taxes charged to operating expense includes a transmission related component of $209.

Schedule Page: 262.1 Line No.: 5 Column: b

FICA taxes include a transmission related component of $6,908 credit.

Schedule Page: 262.1 Line No.: 6 Column: g

FICA taxes include a transmission related component of $8,091 credit.

Schedule Page: 262.1 Line No.: 6 Column: i

FICA taxes charged to operating expense includes a transmission related component of $28,072.

Schedule Page: 262.1 Line No.: 8 Column: b

Federal income taxes include a transmission component of $1,027,364 credit.

Schedule Page: 262.1 Line No.: 8 Column: f

Adjustment for tax billed to affiliate for stranded cost.

Schedule Page: 262.1 Line No.: 8 Column: h

Federal income taxes include a transmission component of $7,932,969 credit.

Schedule Page: 262.1 Line No.: 8 Column: i

Federal income taxes charged to operating expense includes a transmission related component of $10,007,283.

Schedule Page: 262.1 Line No.: 8 Column: l

Total includes $1,529,722 for non-operating taxes, of which $882,821 in transmission related; and $13,442,534 for solar tax credits reclassed from account 236 to account 255 (Accumulated Deferred Investment Tax Credits).

Schedule Page: 262.1 Line No.: 9 Column: b

Medicare taxes include a transmission related component of $1,616 credit.

Schedule Page: 262.1 Line No.: 10 Column: g

Medicare taxes include a transmission related component of $1,892 credit.

Schedule Page: 262.1 Line No.: 10 Column: i

Medicare taxes charged to operating expense includes a transmission related component of $7,961.

Schedule Page: 262.1 Line No.: 14 Column: i

State of Connecticut unemployment taxes charged to operating expense includes a transmission related component of $1,092.

Schedule Page: 262.1 Line No.: 15 Column: i

State of Connecticut insurance premium excise taxes charged to operating expense includes

a transmission related component of $15,540.

Schedule Page: 262.1 Line No.: 16 Column: i

State of Connecticut Corporation Business Taxes charged to operating expense includes a transmission related component of $141.

Schedule Page: 262.1 Line No.: 22 Column: i

Commonwealth of Massachusetts unemployment taxes charged to operating expense includes a transmission related component of $897.

Schedule Page: 262.1 Line No.: 23 Column: b

Commonwealth of Massachusetts corporate income taxes include a transmission related component of $238,322 credit.

Schedule Page: 262.1 Line No.: 23 Column: h

Commonwealth of Massachusetts corporate income taxes include a transmission related component of $1,524,190 debit.

Schedule Page: 262.1 Line No.: 23 Column: i

Commonwealth of Massachusetts corporate income taxes charged to operating expense includes a transmission related component of $443,268.

Schedule Page: 262.1 Line No.: 23 Column: l

Commonwealth of Massachusetts corporate income taxes include a transmission related component of $365,584 credit.

Schedule Page: 262.1 Line No.: 24 Column: i

No transmission component of tangible tax in 2018.

Schedule Page: 262.1 Line No.: 26 Column: i

Commonwealth of Massachusetts universal health taxes charged to operating expense includes a transmission related component of $185.

Schedule Page: 262.1 Line No.: 30 Column: c

Massachusetts local property taxes include a distribution component of $808,794 debit and a transmission component of $339,052 credit.

Schedule Page: 262.1 Line No.: 31 Column: g

Massachusetts local property taxes include a distribution component of $625,855 credit and a transmission component of $889,362 credit.

Schedule Page: 262.1 Line No.: 31 Column: l

Massachusetts local property tax expense charged to other accounts include $62,755 to account 184, $87,394 to account 408.2 and $70,354 to account 163. Included in account 408.2 is a transmission related component of $58,708.

Schedule Page: 262.1 Line No.: 32 Column: i

Local Property Tax - D	21,585,416.78
Local Property Tax - T	26,522,946.92
	48,108,363.70

Information on Formula Rates:

Calculated per company records as stipulated per contract.

Page 106.3 line 23

Schedule Page: 262.1 Line No.: 36 Column: i

State of New Hampshire unemployment taxes charged to operating expense includes a transmission related component of $150.

Schedule Page: 262.1 Line No.: 39 Column: i

District of Columbia unemployment taxes charged to operating expense includes a transmission related component of $1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%	33			411.4	22	
3	4%	585,735			411.4	117,160	
4	7%						
5	10%	2,119,364			411.4	902,198	
6	Solar Credit-West	7,737,152			411.4	394,752	
7	Solar Expansion Cre			23,052,847	411.4	345,475	
8	TOTAL	10,442,284		23,052,847		1,759,607	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Sale/leaseback-East	229,150			411.4	29,576	
12							
13							
14							
15							
16							
17							
18							
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47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
11			2
468,575			3
			4
1,217,166			5
7,342,400			6
22,707,372			7
31,735,524			8
			9
			10
199,574			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
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			43
			44
			45
			46
			47
			48

Schedule Page: 266 Line No.: 8 Column: b

West - At the beginning of the year, the balance of Accumulated Deferred Investment Tax Credits in Account 255 includes a transmission component of $2,420.

Schedule Page: 266 Line No.: 8 Column: f

West - The amount charged to Account 411.4 includes a transmission related component of $1,524 for the year ended December 31, 2018.

Schedule Page: 266 Line No.: 8 Column: h

EAST	WEST	TOTAL
11,381,373	20,553,725	31,935,098

EAST :

Line No	Account Subdivisions a	Balance at Beginning of Year b	Deferred for year		Alloc to Income		Adjustments g	Balance at End of Year h
			Amount d		Amount f			
1	Electric Utility							
2	3%	-			-			-
3	4%	585,512			117,022			468,490
4	7%							-
5	10%	2,107,749			894,990			1,212,759
6	Sale leaseback	229,150			29,576			199,574
7	Solar Expansion Credit	-	9,610,313		109,763			9,500,550
8	TOTAL	2,922,411	9,610,313		1,151,351			11,381,373
9	Other							

WEST:

Line No	Account Subdivisions a	Balance at Beginning of Year b	Deferred for Year		Alloc to Income		Adjustments g	Balance at End of Year h
			Amount d		Amount f			
1	Electric Utility							
2	3%	33			22			11
3	4%	223			138			85
4	7%							-
5	10%	11,615			7,208			4,407
6	Solar Credit	7,737,152			394,752			7,342,400
7	Solar Expansion Credit	-	13,442,534		235,712			13,206,822
8	TOTAL	7,749,023	13,442,534		637,832			20,553,725
9	Other							

FOOTNOTE DATA

Line 8, column b
West - Note that at the beginning of the year, the balance of Accumulated Deferred Investment Tax Credits in Account 255 includes a transmission component of $2,420.

Line 8, column f
West - The amount charged to Account 411.4 includes a transmission related component of $1,524 for the year ended December 31, 2018.

Line 8, column h
West - Note that at the end of the year, the balance of Accumulated Deferred Investment Tax Credits in Account 255 includes a transmission related component of $896.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Decommissioning obligations	1,435,366	242/182	77,885	38,540	1,396,021
2						
3	Disputed property taxes	30,074,318			9,628,837	39,703,155
4						
5	Sale of property clearing	976,791	232	217		976,574
6						
7	Warranty work - electric breakers	94,461	242	6,663		87,798
8						
9	Escheatable monies	2,509,758	232	1,775,729	1,594,277	2,328,306
10						
11	Clean energy bids	1,517,262	254	4,249,881	3,429,212	696,593
12						
13	Contributions in Aid of					
14	Construction-Tax Gross-up					
15	(20 year amortization)	5,665,440	186	26,543,601	27,942,611	7,064,450
16						
17	MATEP Distribution Study				410,512	410,512
18						
19	Minor items	118,556	232	3,842		114,714
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	42,391,952		32,657,818	43,043,989	52,778,123

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Account 282			
2	Electric	1,191,923,425	58,109,220	1,790,342
3	Gas			
4	Transition property			
5	TOTAL (Enter Total of lines 2 thru 4)	1,191,923,425	58,109,220	1,790,342
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,191,923,425	58,109,220	1,790,342
10	Classification of TOTAL			
11	Federal Income Tax	969,568,946	37,201,152	1,314,937
12	State Income Tax	222,354,479	20,908,068	475,405
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
				182/254 .	13,231,406	1,261,473,709	2
							3
							4
					13,231,406	1,261,473,709	5
							6
							7
							8
					13,231,406	1,261,473,709	9
							10
					14,001,541	1,019,456,702	11
					-770,135	242,017,007	12
							13

NOTES (Continued)

Schedule Page: 274 Line No.: 9 Column: b

EAST	WEST	TOTAL
889,610,050	302,313,375	1,191,923,425

WEST:
At the beginning of the year, the total balance of Accumulated Deferred Income Taxes in account 282 includes a transmission related component of $184,905,974.In addition, Account 254 includes a transmission related component of $104,382,688 transferred from this account as a result of the Federal Income Tax Act.

Schedule Page: 274 Line No.: 9 Column: k

EAST	WEST	TOTAL
945,081,038	316,392,671	1,261,473,709

EAST:
Information on Formula Rates Page 106.2 line 1:
Amount as stipulated per contract.

Account 282 balance per balance sheet	$ 945,081,038
ASC740 deferred income taxes (FAS109)	494,564,499
Transmission billing (sheet 3, line 16, col. c)	$1,439,645,537

WEST:
At the end of the year, the total balance of Accumulated Deferred Income Taxes in account 282 includes a transmission related component of $194,260,538.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3		484,036,684	82,986,382	48,382,842
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	484,036,684	82,986,382	48,382,842
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other Income and deductions	2,473,568		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	486,510,252	82,986,382	48,382,842
20	Classification of TOTAL			
21	Federal Income Tax	372,443,810	58,747,302	34,217,848
22	State Income Tax	114,066,442	24,239,080	14,164,994
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	
							1
							2
		182/254	88,306,764		74,793,379	505,126,839	3
							4
							5
							6
							7
							8
			88,306,764		74,793,379	505,126,839	9
							10
							11
							12
							13
							14
							15
							16
							17
468	20,420					2,453,616	18
468	20,420		88,306,764		74,793,379	507,580,455	19
							20
468	14,460		78,831,212		54,092,686	372,220,746	21
	5,960		9,475,552		20,700,693	135,359,709	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 3 Column: b

The disclosure required by FERC Policy Statement PL 19-2-000 is included as a footnote to page 278, Account 254.

EAST	WEST	TOTAL
421,399,236	62,637,448	484,036,684

Schedule Page: 276 Line No.: 9 Column: k

EAST	WEST	TOTAL
441,366,030	63,760,809	505,126,839

Schedule Page: 276 Line No.: 18 Column: b

EAST	WEST	TOTAL
0	2,473,568	2,473,568

Schedule Page: 276 Line No.: 18 Column: k

EAST	WEST	TOTAL
0	2,453,616	2,453,616

Schedule Page: 276 Line No.: 19 Column: b

EAST	WEST	TOTAL
421,399,236	65,111,016	486,510,252

WEST:

At the beginning of the year, the total balance of Accumulated Deferred Income Taxes in Account 283 includes a transmission related component of $6,488,383. In addition, Account 254 includes a transmission related component of $42,622,745 transferred from this account as a result of the Federal Income Tax Act.

Schedule Page: 276 Line No.: 19 Column: k

EAST	WEST	TOTAL
441,366,030	66,214,425	507,580,455

EAST:

Performance reward program	$ 1,536,020	All (Labor)
Bond redemption call premiums	2,852,045	All (Plant)
Pension expense	138,559,388	All (Labor)
Post employment benefits accrued	37,245,182	All (Labor)
Hazardous waste reserves	2,180,423	All (Plant)
Property tax lien date accrual	19,555,401	All (Plant)
Workers compensation gross up payable	4,801,981	All (Labor)

Retail adjuster clause deferrals	39,596,017	Retail Adjuster Clause
Keep cost receivable	10,361,383	Distribution
Storm contingency fund	58,636,044	Distribution
Rate change to 21% in account 283	49,065,168	All (Labor)
Rate change to 21% in account 283	12,104,031	All (Plant)
Rate change to 21% in account 283	20,548,094	Distribution
Rate change to 21% in account 283	16,869,770	Retail Adjuster Clause
ASC 740 deferred income taxes (FAS109)	(60,179,683)	All (Plant)
Goodwill	81,715,431	Regulatory Asset
Other items	5,919,335	All (Plant)
Total	$441,366,030	

Information on Formula Rates Page 106.2 line 1:
Amount as stipulated by contract.

WEST:

	Beginning Balance	Activity	Ending Balance
ASC 740 Gross-Up (FAS 109)	$ 14,435,534	$ (545,014)	$ 13,890,520
ASC 740 Regulatory Asset (FAS 109)	(10,051,924)	(1,562,403)	(11,614,327)
Property Taxes	2,356,891	593,897	2,950,788
Regulatory Deferrals	56,364,640	398,512	56,763,152
Employee Benefits	409,256	860,134	1,269,390
Asset Retirement Obligations	1,170,196	164,365	1,334,561
Other	426,423	1,193,918	1,620,341
TOTAL ACCOUNT 283	$ 65,111,016	$ 1,103,409	$ 66,214,425

Note that at the beginning of the year, the total balance of Accumulated Deferred Income Taxes in Account 283 includes a transmission related component of $6,488,383.

Note that at the end of the year, the total balance of Accumulated Deferred Income Taxes in Account 283 includes a transmission related component of $6,095,274.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Federal income tax rate change	1,087,794,687	190	506,385	16,384,423	1,103,672,725
2						
3	FASB ASC 740 Regulatory Liability	6,332,125			3,690,377	10,022,502
4						
5	AFUDC recorded on transmission	18,310,445	407.4	491,782	5,511,258	23,329,921
6	construction work in progress					
7						
8	Transition Reconciliation					
9	D.P.U. 96-23, 97-111, 97-120					
10	This account captures the difference between					
11	costs incurred related to the transition charge					
12	and the amounts actually billed to customers	6,638,904	407.3/431	7,567,252	2,318,508	1,390,160
13						
14	Transmission Reconciliation: D.P.U. 06-40, 97-120					
15	The Company defers the difference between					
16	the transmission revenues billed to customers					
17	and the cost to provide transmission service.	20,691,339	565	7,076,070	79,782,704	93,397,973
18						
19	Pension and PBOP:					
20	D.P.U. 03-47, 06-55					
21	which requires the Company to defer					
22	pension and PBOP expense that exceeds the					
23	current rate recovery. Each year's deferred					
24	amount is amortized over the subsequent three					
25	year period.	43,542,836	Footnote	44,538,454	38,162,436	37,166,818
26						
27	Pension and PBOP ASC 715	112,573,795	128	35,677,043		76,896,752
28						
29	Basic Service Cost Adjustment D.P.U. 03-88-A-F	101,417	407.4/431	450,629	178,245	-170,967
30						
31	Solar Program D.P.U. 09-05	331,237	182.3	331,237		
32						
33	Revenue Decoupling D.P.U. 17-05				3,502,563	3,502,563
34						
35	Storm Fund Post 2-1-18 D.P.U. 17-05				6,989,347	6,989,347
36						
37	Basic Service Reconciliation: D.P.U. 06-40					
38	The Company defers the cost to					
39	provide service to customers compared					
40	to amounts billed to customers, plus carrying					
41	TOTAL	1,296,363,587		96,675,007	174,590,693	1,374,279,273

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	charges				4,389,972	4,389,972
2						
3	Deferred net metering costs D.P.U. 12-116				12,735,129	12,735,129
4						
5	Uncollectibles Associated with Basic Service					
6	D.P.U. 03-88A				181,536	181,536
7						
8	Minor items	46,802	407.3	36,155	764,195	774,842
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
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21						
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28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	1,296,363,587		96,675,007	174,590,693	1,374,279,273

Schedule Page: 278 Line No.: 1 Column: f

East Distribution	$ 850,142,721
West Distribution	106,349,849
West Transmission	147,180,155
Total	$1,103,672,725

On December 22, 2017, the President signed into law the Tax Cuts and Jobs Act. The Tax Cuts and Jobs Act, among other things, reduced the federal corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018. This means that, beginning January 1, 2018, companies subject to the Commission's jurisdiction will compute income taxes owed to the Internal Revenue Service based on a 21 percent tax rate. The tax rate reduction will result in less corporate income tax expense going forward.

(1) In accounting for the impact of the income tax rate change, FERC accounts 190, 282, and 283 were reduced to reflect lower required balances in Accumulated Deferred Income Taxes ("ADIT"). The offsetting entry was to account 182.3 and 254.

(2) The affected ADIT accounts were remeasured by comparing ADIT on cumulative temporary differences for each item in accounts 190, 282, and 283 at a Federal income rate of 21% to the ADIT at 35%. The difference between the two represents the excess ADIT.

(3) The related amounts associated with the reversal and elimination of ADIT balances in these accounts at December 31, 2018 are as follows:

	Unprotected 190 and 283	Protected 282	Revenue Requirement Adjustment	Total ADIT Decrease
Distribution	170,137,126	402,119,180	209,464,970	$ 781,721,276
Transmission	12,210,411	264,305,451	112,975,415	389,491,277
Sub- total ADIT Reduction	182,347,537	666,424,631	322,440,385	1,171,212,553
Reduction to 182.3 Goodwill				(67,539,828)
Total				$ 1,103,672,725

Transmission excess ADIT for East is in accounts 190 and 283 is allocated at 9.419% and in account 282 at 31.874%. Transmission excess ADIT for West is on a direct charge method. These methods are consistent with the methodologies in the FERC tariff for each of the divisions.

(4) The amount of excess ADIT that is protected and unprotected is included in the table in item 3.

(5) The excess ADIT is amortized to account 411.1.

(6) The amortization period of the excess ADIT to be refunded through rates ranges from 5 years to 10 years for unprotected ADIT. Protected ADIT will be refunded using the Average Rate Assumption

Method.

WEST:

Information on Formula Rates:

Page 106.3 line 9

Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II

Schedule Page: 278 Line No.: 3 Column: f

West Distribution	$10,021,446
West Transmission	1,056
Total	$10,022,502

Schedule Page: 278 Line No.: 5 Column: f

East Transmission	$14,951,855
West Transmission	8,378,066
Total	$23,329,921

Schedule Page: 278 Line No.: 25 Column: c

Account:	Amount:
456	$23,859,413
926	19,730,000
440	949,041
Total	$44,538,454

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	1,383,550,022	1,269,750,366
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,375,030,078	1,264,358,707
5	Large (or Ind.) (See Instr. 4)	124,894,540	113,966,319
6	(444) Public Street and Highway Lighting	14,599,693	14,598,873
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	2,898,074,333	2,662,674,265
11	(447) Sales for Resale	73,125,096	77,087,381
12	TOTAL Sales of Electricity	2,971,199,429	2,739,761,646
13	(Less) (449.1) Provision for Rate Refunds	-5,255,654	2,998,459
14	TOTAL Revenues Net of Prov. for Refunds	2,976,455,083	2,736,763,187
15	Other Operating Revenues		
16	(450) Forfeited Discounts	4,510,904	4,317,226
17	(451) Miscellaneous Service Revenues	1,611,900	315,790
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	14,484,140	13,077,370
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-4,944,948	86,484,270
22	(456.1) Revenues from Transmission of Electricity of Others	367,750,994	371,595,751
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	383,412,990	475,790,407
27	TOTAL Electric Operating Revenues	3,359,868,073	3,212,553,594

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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
8,181,727	7,720,675	1,230,516	1,221,799	2
				3
14,028,514	14,021,451	185,601	184,743	4
1,687,971	1,691,321	1,760	1,801	5
101,172	104,986	9,668	9,679	6
				7
				8
				9
23,999,384	23,538,433	1,427,545	1,418,022	10
1,262,293	1,680,697	17	17	11
25,261,677	25,219,130	1,427,562	1,418,039	12
				13
25,261,677	25,219,130	1,427,562	1,418,039	14

Line 12, column (b) includes $ -14,987,833 of unbilled revenues.

Line 12, column (d) includes -94,427 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 4 Column: b

Commercial

Schedule Page: 300 Line No.: 5 Column: b

Industrial

Schedule Page: 300 Line No.: 10 Column: d

Instruction 9 - Unmetered Sales (MWH)

Customer Class	East	West	Total
Residential	1,038	1,700	2,738
Commercial	5,995	10,744	16,739
Industrial	28	1,396	1,424
Street Light	80,458	18,430	98,888
Total	**87,519**	**32,270**	**119,789**

The total "Megawatt Hours Sold" to retail customers represents the delivery of energy to all distribution customers including energy for those customers who have chosen third party suppliers.

Schedule Page: 300 Line No.: 17 Column: b

Description	East	West	Total
Reconnect Fees	$ 918,800	$ 259,207	$ 1,178,007
Return Check Fees	362,270	61,111	423,381
Other Service Fees	49,824	(39,312)	10,512
Total	**$ 1,330,894**	**$ 281,006**	**$ 1,611,900**

Schedule Page: 300 Line No.: 19 Column: b

Description	East	West	Total
Associated Company Rents	$ 1,654,589		$ 1,654,589
Pole Attachment Rents	5,045,625	$ 474,956	5,520,581
Distribution - Wireless and Other Rents	2,424,141	565,792	2,989,933
Transmission - Wireless and Other Rents	3,816,219	502,818	4,319,037
Total	**$ 12,940,574**	**$ 1,543,566**	**$ 14,484,140**

Schedule Page: 300 Line No.: 21 Column: b

Description	East	West	Total
Energy Efficiency Revenue	$ 6,998,810		$ 6,998,810
Renewable Energy Certificates		$ 2,971,222	2,971,222
MBTA distribution facilities	2,394,957		2,394,957
MATEP distribution	1,654,568		1,654,568
Massport distribution facilities	2,656,631		2,656,631
PAM carrying charge	4,247,413	56,404	4,303,817
Enhanced billing & metering services	304,797		304,797
Net metering revenue	(33,000,874)		(33,000,874)
Solar Expansion	1,194,281	2,710,788	3,905,069
Local facility charges		323,448	323,448
Wholesale distribution services		2,244,242	2,244,242
Other revenue	298,365		298,365
Total	**$(13,251,052)**	**$ 8,306,104**	**$ (4,944,948)**

EAST:

Page 106 lines 10 and 13 Terms stipulated per contract.

Schedule Page: 300 Line No.: 22 Column: b

Refer to Pages 328-330 for detail.

FOOTNOTE DATA

EAST:

Information on Formula Rates:

Page 106 lines 10, 13, 23, 26, 30, 35	Terms stipulated per contract.
Page 106.1 lines 1, 8, 15, 20, 27, 34	Terms stipulated per contract.
Page 106.2 lines 1, 5	Terms stipulated per contract.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	Not Applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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26					
27					
28					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential (Account 440)					
2	All Service Areas					
3	R-1 Residential	6,408,282	1,160,481,879	1,009,426	6,348	0.1811
4	R-2 Residential Assistance	734,459	64,419,504	119,048	6,169	0.0877
5	R-3 Res. Space Heating	885,614	150,357,940	90,398	9,797	0.1698
6	R-4 Res. Space Heating Assist.	89,160	8,028,390	7,195	12,392	0.0900
7	S-1 Street Lighting	2,205	594,416	2,137	1,032	0.2696
8	S-2 Street Lighting Cust Owned	532	42,314	12	44,333	0.0795
9	West					
10	23 Optional Water Heating	166	17,130	6	27,667	0.1032
11	T-0 Small General Service TOU	11	949	1	11,000	0.0863
12	T-2 Large Primary Service TOU	14,489	1,093,122	8	1,811,125	0.0754
13	G-0 Small General Service	30,774	5,095,635	3,321	9,266	0.1656
14	G-2 Primary General Service	44,456	3,929,729	96	463,083	0.0884
15	99 Unmetered	1	328	1	1,000	0.3280
16	Unbilled Revenue	-28,422	-10,511,314			0.3698
17	less: Duplicate Customers			-1,133		
18	Total Residential	8,181,727	1,383,550,022	1,230,516	6,649	0.1691
19						
20	Commercial (Account 442)					
21	All Service Areas					
22	R-1 Residential	17,415	2,141,436	2,751	6,330	0.1230
23	R-3 Res. Space Heating	3,789	419,555	72	52,625	0.1107
24	S-1 Street Lighting	15,372	2,638,517	5,916	2,598	0.1716
25	S-2 Street Lighting Cust Owned	143	4,540	14	10,214	0.0317
26	Greater Boston					
27	G-1 General Service	524,266	94,880,592	74,325	7,054	0.1810
28	G-2 General Service	2,594,552	363,499,929	28,703	90,393	0.1401
29	G-3 General Service TOU	2,305,084	159,767,456	348	6,623,805	0.0693
30	T-1 Optional Time of Use	1,426	30,969	201	7,095	0.0217
31	T-2 Time of Use	3,878,999	364,829,010	3,023	1,283,162	0.0941
32	WR MWRA	104,131	3,772,286	2	52,065,500	0.0362
33	SB-G3 Gen. Service Standby	17,466	1,163,712	1	17,466,000	0.0666
34	Contract-Amtrak Transmission	40,766	1,239,830	1	40,766,000	0.0304
35	Cambridge					
36	G-0 General (Non-Demand)	37,937	3,909,663	5,278	7,188	0.1031
37	G-1 General	204,838	18,094,618	2,000	102,419	0.0883
38	G-2 Lg. Gen. TOU/Second Serv	569,236	39,397,508	461	1,234,785	0.0692
39	G-3 Lg. Gen. TOU/13.8KV Serv	479,945	22,218,133	72	6,665,903	0.0463
40	G-4 Optional General TOU	5,008	369,253	36	139,111	0.0737
41	TOTAL Billed	24,093,811	2,913,062,166	1,427,545	16,878	0.1209
42	Total Unbilled Rev.(See Instr. 6)	-94,427	-14,987,833	0	0	0.1587
43	TOTAL	23,999,384	2,898,074,333	1,427,545	16,812	0.1208

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	G-5 Commercial Space Heating	6,655	535,216	57	116,754	0.0804
2	G-6 Opt. Gen. TOU (Non-Demand)		822			
3	SB-1 Standby Service	27,788	1,448,509	1	27,788,000	0.0521
4	MS-1 Maintenance Service	25,983	590,249	1	25,983,000	0.0227
5	SS-1 Supplemental Service	51,866	3,219,748	1	51,866,000	0.0621
6	SB-G3 Gen. Service Standby	33,514	3,238,737	1	33,514,000	0.0966
7	Contract-MIT MAG Lab	690	136,502	1	690,000	0.1978
8	South Shore / Cape & Vineyard					
9	G-1 General	983,055	97,313,196	44,957	21,867	0.0990
10	G-2 Med. General Time of Use	412,826	29,312,190	419	985,265	0.0710
11	G-3 Lg. General Time of Use	232,141	15,633,448	52	4,464,250	0.0673
12	G-4 General Power	1,239	103,302	15	82,600	0.0834
13	G-5 Commercial Space Heating	12,831	1,371,879	742	17,292	0.1069
14	G-6 All-Electric School	4,738	289,492	7	676,857	0.0611
15	G-7 Optional General TOU	55,191	4,457,166	604	91,376	0.0808
16	West					
17	23 Optional Water Heating	20	6,409	16	1,250	0.3205
18	24 Optional Church	6,076	877,387	191	31,812	0.1444
19	T-0 Small General Service TOU	1,608	129,586	12	134,000	0.0806
20	T-2 Large Primary Service TOU	431,944	30,045,252	158	2,733,823	0.0696
21	T-4 Primary General Service TOU	7,094	587,639	12	591,167	0.0828
22	T-5 Extra Lg. Primary Service TOU	179,137	11,779,548	9	19,904,111	0.0658
23	G-0 Small General Service	537,082	75,106,286	17,249	31,137	0.1398
24	G-2 Primary General Service	274,500	23,904,025	747	367,470	0.0871
25	99 Unmetered	1,224	116,713	104	11,769	0.0954
26	Unbilled Revenue	-59,061	-3,550,230			0.0601
27	less: Duplicate Customers			-2,959		
28	Total Commercial	14,028,514	1,375,030,078	185,601	75,584	0.0980
29						
30	Industrial (Account 442)					
31	All Service Areas					
32	S-1 Street Lighting	1,424	180,501	185	7,697	0.1268
33	Greater Boston					
34	G-1 General Service	1,434	194,627	154	9,312	0.1357
35	G-2 General Service	46,361	7,210,144	485	95,590	0.1555
36	G-3 General Service TOU	655,189	46,525,147	114	5,747,272	0.0710
37	T-2 Time of Use	114,112	13,082,544	120	950,933	0.1146
38	Cambridge					
39	G-0 General (Non-Demand)	25	2,491	5	5,000	0.0996
40	G-2 Lg. Gen. TOU/Second Serv	2,280	194,248	4	570,000	0.0852
41	TOTAL Billed	24,093,811	2,913,062,166	1,427,545	16,878	0.1209
42	Total Unbilled Rev.(See Instr. 6)	-94,427	-14,987,833	0	0	0.1587
43	TOTAL	23,999,384	2,898,074,333	1,427,545	16,812	0.1208

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	G-3 Lg. Gen. TOU/13.8KV Serv	21,539	1,167,935	6	3,589,833	0.0542
2	South Shore / Cape & Vineyard					
3	G-1 General	9,534	1,025,038	120	79,450	0.1075
4	G-2 Med. General Time of Use	44,457	3,700,876	57	779,947	0.0832
5	G-3 Lg. General Time of Use	173,700	9,481,562	35	4,962,857	0.0546
6	G-4 General Power	1,092	113,294	13	84,000	0.1037
7	G-7 Optional General TOU	129	17,450	4	32,250	0.1353
8	Contract-Canal	14,499	1,951,736	2	7,249,500	0.1346
9	West					
10	T-0 Small General Service TOU	117	14,197	2	58,500	0.1213
11	T-2 Large Primary Service TOU	265,753	17,631,449	71	3,743,000	0.0663
12	T-4 Primary General Service TOU	1,528	178,552	5	305,600	0.1169
13	T-5 Extra Lg. Primary Service TOU	260,943	14,339,751	6	43,490,500	0.0550
14	G-0 Small General Service	25,060	3,358,409	393	63,766	0.1340
15	G-2 Primary General Service	55,805	5,453,318	157	355,446	0.0977
16	Unbilled Revenue	-7,010	-928,729			0.1325
17	less: Duplicate Customers			-178		
18	Total Industrial	1,687,971	124,894,540	1,760	959,074	0.0740
19						
20	Street Lighting (Account 444)					
21	All Service Areas					
22	S-1 Street Lighting	37,699	9,268,265	3,758	10,032	0.2458
23	S-2 Street Lighting Cust Owned	61,094	5,002,735	5,117	11,939	0.0819
24	Cambridge					
25	G-0 General (Non-Demand)	917	113,660	228	4,022	0.1239
26	G-1 General	135	12,956	4	33,750	0.0960
27	South Shore / Cape & Vineyard					
28	G-1 General	1,158	177,069	513	2,257	0.1529
29	West					
30	G-0 Small General Service	8	2,075	5	1,600	0.2594
31	99 Unmetered	95	20,493	43	2,209	0.2157
32	Unbilled Revenue	66	2,440			0.0370
33	Total Street Lighting	101,172	14,599,693	9,668	10,465	0.1443
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	24,093,811	2,913,062,166	1,427,545	16,878	0.1209
42	Total Unbilled Rev.(See Instr. 6)	-94,427	-14,987,833	0	0	0.1587
43	TOTAL	23,999,384	2,898,074,333	1,427,545	16,812	0.1208

FOOTNOTE DATA

Schedule Page: 304 Line No.: 1 Column: a

MWh Sold (Column b) represents all energy deliveries to customers. Revenues (Column c) include delivery revenues as well as energy revenues for those customers who receive their energy supply from NSTAR Electric Company via Basic Service. Since revenues do not include the supply cost to customers of competitive energy suppliers, revenue per KWh sold (Column f) is not necessarily representative of the average customer bill.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1						
2	Requirement Service:					
3	The Connecticut Light and Power Company	RQ	10			
4	National Grid	RQ	2			
5	New York State Electric & Gas Corp.	RQ	2			
6						
7	Nonassociated Utilities/Companies					
8	ISO-New England	OS	10			
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
					1
					2
49		5,069	5,904	10,973	3
182		22,063	13,512	35,575	4
45	3,382	1,919		5,301	5
					6
					7
1,262,017		48,152,280	24,920,967	73,073,247	8
					9
					10
					11
					12
					13
					14
276	3,382	29,051	19,416	51,849	
1,262,017	0	48,152,280	24,920,967	73,073,247	
1,262,293	**3,382**	**48,181,331**	**24,940,383**	**73,125,096**	

FOOTNOTE DATA

Schedule Page: 310 Line No.: 3 Column: a

Associated Utility

Schedule Page: 310 Line No.: 3 Column: c

MBR FERC Electric Tariff, Third Revised Vol. No. 10, 1.0.0

Schedule Page: 310 Line No.: 4 Column: c

NSTAR - FERC Electric Tariff Original Volume No. 2

Schedule Page: 310 Line No.: 8 Column: b

Short-term energy and capacity sales.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)		
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)		
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)		
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	23,844	23,831
63	(547) Fuel		
64	(548) Generation Expenses	247,527	189,007
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	271,371	212,838
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	271,371	212,838
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,059,530,159	836,223,072
77	(556) System Control and Load Dispatching	961,586	1,002,932
78	(557) Other Expenses	56,732	10,216,095
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	1,060,548,477	847,442,099
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,060,819,848	847,654,937
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,096,851	5,425,056
84			
85	(561.1) Load Dispatch-Reliability	1,148,881	1,166,148
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,025,018	1,020,373
87	(561.3) Load Dispatch-Transmission Service and Scheduling	510,333	505,584
88	(561.4) Scheduling, System Control and Dispatch Services	14,257,125	15,142,905
89	(561.5) Reliability, Planning and Standards Development	1,725,304	1,701,943
90	(561.6) Transmission Service Studies	684,619	733,592
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	19,593	17,323
93	(562) Station Expenses	4,349,658	2,949,209
94	(563) Overhead Lines Expenses	2,146,390	534,469
95	(564) Underground Lines Expenses	4,953,941	5,078,340
96	(565) Transmission of Electricity by Others	414,526,625	405,297,157
97	(566) Miscellaneous Transmission Expenses	240,115	367,240
98	(567) Rents	91,574	75,693
99	TOTAL Operation (Enter Total of lines 83 thru 98)	451,776,027	440,015,032
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	401,228	416,760
102	(569) Maintenance of Structures	558,414	406,031
103	(569.1) Maintenance of Computer Hardware	315,855	519,180
104	(569.2) Maintenance of Computer Software	616,994	638,095
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,129,469	1,952,781
108	(571) Maintenance of Overhead Lines	10,438,202	9,562,414
109	(572) Maintenance of Underground Lines	-101,422	8,232,725
110	(573) Maintenance of Miscellaneous Transmission Plant	595	317
111	TOTAL Maintenance (Total of lines 101 thru 110)	15,359,335	21,728,303
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	467,135,362	461,743,335

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	278,766	427,859
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	278,766	427,859
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	278,766	427,859
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	13,683,293	14,947,049
135	(581) Load Dispatching	4,161,234	5,309,236
136	(582) Station Expenses	5,910,675	6,006,577
137	(583) Overhead Line Expenses	12,982,143	11,465,332
138	(584) Underground Line Expenses	14,690,084	10,285,360
139	(585) Street Lighting and Signal System Expenses	995,890	916,291
140	(586) Meter Expenses	1,374,080	1,785,117
141	(587) Customer Installations Expenses	1,356,747	1,231,047
142	(588) Miscellaneous Expenses	6,744,017	2,827,087
143	(589) Rents	519,973	1,374,040
144	TOTAL Operation (Enter Total of lines 134 thru 143)	62,418,136	56,147,136
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	287,512	418,451
147	(591) Maintenance of Structures	342,764	407,960
148	(592) Maintenance of Station Equipment	3,654,195	3,855,042
149	(593) Maintenance of Overhead Lines	55,587,281	41,519,207
150	(594) Maintenance of Underground Lines	8,588,056	9,721,350
151	(595) Maintenance of Line Transformers	1,003,248	1,148,771
152	(596) Maintenance of Street Lighting and Signal Systems	508,056	381,885
153	(597) Maintenance of Meters	1,334,033	1,210,926
154	(598) Maintenance of Miscellaneous Distribution Plant	10,449,290	7,256,561
155	TOTAL Maintenance (Total of lines 146 thru 154)	81,754,435	65,920,153
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	144,172,571	122,067,289
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,833	47,548
160	(902) Meter Reading Expenses	7,039,043	7,076,897
161	(903) Customer Records and Collection Expenses	49,578,656	47,158,258
162	(904) Uncollectible Accounts	32,442,012	37,564,591
163	(905) Miscellaneous Customer Accounts Expenses	3,085,088	4,404,799
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	92,146,632	96,252,093

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	312,867,068	306,274,455
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	385,185	346,151
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	313,252,253	306,620,606
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses	39,030	55,740
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	39,030	55,740
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	84,780,703	82,508,862
182	(921) Office Supplies and Expenses	4,881,672	5,363,749
183	(Less) (922) Administrative Expenses Transferred-Credit	6,653,671	6,191,068
184	(923) Outside Services Employed	35,004,366	37,807,149
185	(924) Property Insurance	1,048,492	1,167,165
186	(925) Injuries and Damages	10,965,412	10,684,251
187	(926) Employee Pensions and Benefits	-6,245,174	21,424,626
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	11,947,392	11,762,078
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	272,376	246,003
192	(930.2) Miscellaneous General Expenses	3,757,305	9,575,774
193	(931) Rents	2,825,890	3,209,438
194	TOTAL Operation (Enter Total of lines 181 thru 193)	142,584,763	177,558,027
195	Maintenance		
196	(935) Maintenance of General Plant	21,231	99,526
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	142,605,994	177,657,553
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,220,450,456	2,012,479,412

Schedule Page: 320 Line No.: 85 Column: b
East total is $1,148,881. These costs are 100% internal costs.

Schedule Page: 320 Line No.: 85 Column: c
East total is $1,166,130. These costs are 100% internal costs.

Schedule Page: 320 Line No.: 86 Column: b
East total is $1,025,018. These costs are 100% internal costs.

Schedule Page: 320 Line No.: 86 Column: c
East total is $1,020,365. These costs are 100% internal costs.

Schedule Page: 320 Line No.: 87 Column: b
East total is $510,333. These costs are 100% internal costs.

Schedule Page: 320 Line No.: 87 Column: c
East total is $505,558. These costs are 100% internal costs.

Schedule Page: 320 Line No.: 88 Column: b
East total is $12,990,162. These costs are 100% external costs.

Schedule Page: 320 Line No.: 88 Column: c
East total is $13,834,851. These costs are 100% external costs.

Schedule Page: 320 Line No.: 89 Column: b
East total is $1,362,037. Internal costs and external costs are $1,091,075 and $270,962, respectively.

Schedule Page: 320 Line No.: 89 Column: c
East total is $1,302,216. Internal costs and external costs are $1,048,426 and $253,790, respectively.

Schedule Page: 320 Line No.: 90 Column: b
East total is $468,520. These costs are 100% internal costs.

Schedule Page: 320 Line No.: 90 Column: c
East total is $510,973. These costs are 100% internal costs.

Schedule Page: 320 Line No.: 92 Column: b
East total is $19,650. These costs are 100% external costs.

Schedule Page: 320 Line No.: 92 Column: c
East total is $17,254. These costs are 100% external costs.

Schedule Page: 320 Line No.: 96 Column: b

East total is $401,237,982.

East Information on Formula Rates Page 106 line 4:
Hydro Quebec DC Phase I Support see page 332 col g ln 6
Hydro Quebec DC Phase II Support see page 332 col g ln 7

Schedule Page: 320 Line No.: 96 Column: c
East total is $393,996,732.

East-Information on Formula Rates Page 106 line 4:
Hydro Quebec DC Phase I Support see page 332 col g ln 5
Hydro Quebec DC Phase II Support see page 332 col g ln 6

Schedule Page: 320 Line No.: 98 Column: b
East total is $47,732.

East - Information on Formula Rates Page 106 line 4:

Schedule Page: 320 Line No.: 98 Column: c
East total is $68,105.

East - Information on Formula Rates Page 106 line 4:

Schedule Page: 320 Line No.: 99 Column: b

Line No.	Account	TOTAL	EAST	WEST TOTAL	WEST DISTRIBUTION	WEST TRANSMISSION
83	560	6,096,851	4,423,477	1,673,374		1,673,374
85	561.1	1,148,881	1,148,881	-		
86	561.2	1,025,018	1,025,018	-		
87	561.3	510,333	510,333	-		
88	561.4	14,257,125	12,990,162	1,266,963	1,266,963	
89	561.5	1,725,304	1,362,037	363,267	46,460	316,807
90	561.6	684,619	468,520	216,099		216,099
92	561.8	19,593	19,650	(57)		(57)
93	562	4,349,658	2,317,792	2,031,866		2,031,866
94	563	2,146,390	1,617,127	529,263		529,263
95	564	4,953,941	4,745,653	208,288		208,288
96	565	414,526,625	401,237,982	13,288,643	12,930,585	358,058
97	566	240,115	108,142	131,973		131,973
98	567	91,574	47,732	43,842		43,842
99	Total	451,776,027	432,022,506	19,753,521	14,244,008	5,509,513

Schedule Page: 320 Line No.: 99 Column: c

Line No.	Account	TOTAL	EAST	WEST
83	560	5,425,056	3,963,330	1,461,726
85	561.1	1,166,148	1,166,130	18
86	561.2	1,020,373	1,020,365	8
87	561.3	505,584	505,558	26
88	561.4	15,142,905	13,834,851	1,308,054
89	561.5	1,701,943	1,302,216	399,727
90	561.6	733,592	510,973	222,619
92	561.8	17,323	17,254	69
93	562	2,949,209	2,057,264	891,945
94	563	534,469	363,025	171,444
95	564	5,078,340	4,740,651	337,689
96	565	405,297,157	393,996,732	11,300,425
97	566	367,240	235,653	131,587
98	567	75,693	68,105	7,588
99	Total	440,015,032	423,782,107	16,232,925

Schedule Page: 320 Line No.: 111 Column: b

Line No.	Account	TOTAL	EAST	WEST TOTAL	WEST DISTRIBUTION	WEST TRANSMISSION

101	568	401,228	168,358	232,870		232,870
102	569.0	558,414	306,488	251,926	730	251,196
103	569.1	315,855	315,855	-		-
104	569.2	616,994	616,994	-		-
107	570	3,129,469	2,740,190	389,279	(1)	389,280
108	571	10,438,202	4,749,564	5,688,638		5,688,638
109	572	(101,422)	(101,449)	27		27
110	573	595	-	595		595
111	Total	15,359,335	8,796,000	6,563,335	729	6,562,606

Schedule Page: 320 Line No.: 111 Column: c

Line No.	Account	TOTAL	EAST	WEST
101	568	416,760	198,945	217,815
102	569.0	406,031	186,469	219,562
103	569.1	519,180	519,180	-
104	569.2	638,095	638,095	-
107	570	1,952,781	1,515,523	437,258
108	571	9,562,414	4,729,379	4,833,035
109	572	8,232,725	8,232,659	66
110	573	317	-	317
111	Total	21,728,303	16,020,250	5,708,053

WEST:
Calculated per company records as stipulated per contract.
Reference Page 106.3 line 23.

Schedule Page: 320 Line No.: 112 Column: b

WEST:
Information on Formula Rates:
Calculated per company records as stipulated per contract.
Page 106.3 line 15 and 23

Schedule Page: 320 Line No.: 121 Column: b

Line No.	Account	TOTAL	EAST	WEST TOTAL	WEST DISTRIBUTION	WEST TRANSMISSION
121	575.7	278,766	236,628	42,138	42,138	-

Schedule Page: 320 Line No.: 121 Column: c

Line No.	Account	TOTAL	EAST	WEST
121	575.7	427,859	388,066	39,793

Schedule Page: 320 Line No.: 184 Column: c

EAST:
NSTAR Electric Company received FERC order ER16-1023 allowing collection of $7,800,000 of merger-related costs over a twelve month period commencing on June 1, 2016. In 2017, $3,250,000 was expensed to account 923 and subject to 100% recovery from transmission customers.

Schedule Page: 320 Line No.: 185 Column: c

WEST:
Note that for the year ended December 31, 2017, the total amount of Property Insurance in Account 924 includes a transmission related component of $134,032.

Schedule Page: 320 Line No.: 187 Column: b

EAST:

Postretirement Benefits Other Than Pension (PBOP)	$(36,897,000)
Capitalized and Other	19,368,000
Recoverable PBOP Expense	$(17,529,000)

Schedule Page: 320 Line No.: 187 Column: c

EAST:

Postretirement Benefits Other Than Pension (PBOP)	$(32,217,000)
Capitalized and Other	18,720,000
Recoverable PBOP Expense	$(13,497,000)

Schedule Page: 320 Line No.: 189 Column: c

WEST:
Note that for the year ended December 31, 2017, the total amount of Regulatory Commission Expenses in Account 928 includes a transmission related component of $373,726.

Schedule Page: 320 Line No.: 191 Column: c

WEST:
Note that for the year ended December 31, 2017, the total amount of General Advertising Expenses in Account 930.1 includes a transmission related component of $7,430.

Schedule Page: 320 Line No.: 196 Column: c

WEST:
Note that for the year ended December 31, 2017, the total amount of Administrative and General Expenses in Account 920 through 935 includes a transmission related component of $12,577,615 which includes a transmission merger amortization expense of $1,458,331.

Schedule Page: 320 Line No.: 197 Column: b

Line No.	Account	TOTAL	EAST	WEST TOTAL	WEST DISTRIBUTION	WEST TRANSMISSION
181	920	84,780,703	66,474,318	18,306,385	11,244,272	7,062,113
182	921	4,881,672	3,793,909	1,087,763	756,996	330,767
183	922	(6,653,671)	(5,685,942)	(967,729)	(613,021)	(354,708)
184	923	35,004,366	27,914,652	7,089,714	4,377,385	2,712,329
185	924	1,048,492	827,708	220,784	93,625	127,159
186	925	10,965,412	8,078,783	2,886,629	2,582,180	304,449
187	926	(6,245,174)	(6,816,665)	571,491	219,398	352,093
189	928	11,947,392	10,139,928	1,807,464	1,424,845	382,619
191	930.1	272,376	207,274	65,102	63,629	1,473
192	930.2	3,757,305	2,977,036	780,269	486,589	293,680

193	931	2,825,890	2,307,717	518,173	171,405	346,768
196	935	21,231	1,149	20,082	13,074	7,008
197	Total	142,605,994	110,219,867	32,386,127	20,820,377	11,565,750

Schedule Page: 320 Line No.: 197 Column: c

Line No.	Account	TOTAL	EAST	WEST
181	920	82,508,862	63,602,187	18,906,675
182	921	5,363,749	4,111,268	1,252,481
183	922	(6,191,068)	(5,253,075)	(937,993)
184	923	37,807,149	29,671,648	8,135,501
185	924	1,167,165	930,834	236,331
186	925	10,684,251	9,010,252	1,673,999
187	926	21,424,626	19,640,559	1,784,067
189	928	11,762,078	10,011,774	1,750,304
191	930.1	246,003	158,361	87,642
192	930.2	9,575,774	7,491,466	2,084,308
193	931	3,209,438	2,681,689	527,749
196	935	99,526	-	99,526
197	Total	177,657,553	142,056,963	35,600,590

WEST:
Note that for the year ended December 31, 2017, the total amount of Administrative and General Expenses in Account 920 through 935 includes a transmission related component of $12,577,615 which includes a transmission merger amortization expense of $1,458,331.

Schedule Page: 320 Line No.: 198 Column: b

EAST:
-Information on Formula Rates: Page 106.2 line 1:
Amount as stipulated per contract.

Schedule Page: 320 Line No.: 198 Column: c

EAST-Information on Formula Rates Page 106.2 line 1:
Amount as stipulated per contract.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	EAST					
2						
3	Nonassociated Utilities/Companies:					
4	Competitive Suppliers	OS				
5	Enel Green Power North America, Inc.	LU		7.8	16.3	
6	Massachusetts Bay	LU		14.3	14.7	
7	Vermont Yankee Nuclear Power Corp.	LU	12			
8	Atlantic Renewables Project, LLC	LU	1			
9	Atlantic Renewables Project, LLC	OS				
10	Blue Sky East, LLC	LU	1			
11	Blue Sky East, LLC	OS				
12	Blue Sky West Holdings, LLC	LU	1			
13	Blue Sky West Holdings, LLC	OS				
14	Direct Energy Business Marketing, LLC	SF	1			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	DTE Energy Trading, Inc.	SF	1			
2	Emera Energy Services, Inc.	SF	1			
3	Evergreen Wind Power II, LLC	LU	1			
4	Evergreen Wind Power II, LLC	OS				
5	Exelon Generation Corp, LLC	SF	11			
6	Groton Wind, LLC	LU	1			
7	Groton Wind, LLC	OS				
8	National Grid	OS				
9	New England Wind, LLC	LU	1			
10	New England Wind, LLC	OS				
11	NextEra Energy Power Marketing, LTD	SF	1			
12	TransCanada Power Marketing, LTD	SF	1			
13	TransCanada Maine Wind, LLC	LU	1			
14	TransCanada Maine Wind, LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Vitol, Inc.	SF	1			
2						
3	Municipals:					
4	Middleborough Gas and Electric Depart.	OS				
5	Reading Municipal Light Department	OS				
6						
7	Other Sellers:					
8	Basic Service Deferral	OS				
9	Basic Service Deferral	AD				
10	MA Renewable Portfolio Standards	OS				
11	Net Metering Deferral	OS				
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	WEST					
2						
3	Associated Utilities:					
4	Connecticut Light & Power Company	OS				
5	Connecticut Yankee Atomic Power Co.	LU	CYAPC1			
6	Maine Yankee Atomic Power Company	LU	MYACP1			
7	Yankee Atomic Electric Company	LU	YAEC1			
8						
9	Nonassociated Utilities/Companies:					
10	Blue Sky West Holdings LLC	LU				
11	Competitive Suppliers	OS				
12	Direct Energy Business Marketing, LLC	OS				
13	DTE Energy Trading, Inc.	OS				
14	Evergreen Wind Power II, LLC	LU				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Exelon Generation Company, LLC	OS				
2	Green Mountain Power	OS				
3	ISO New England	OS	ISO-NE			
4	National Grid	OS				
5	NextEra Energy Power Marketing, LLC	OS				
6	Noble Passadumkeag Windpark, LLC	LU				
7	TransCanada Power Marketing. LtTD	OS				
8	Vermont Yankee Nuclear Power Corp.	LU	VYNPC 12			
9						
10	Municipals:					
11	Pittsfield, City of	OS				
12	Pittsfield, City of	AD				
13	Town of Lee Board of Public Works	OS				
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Other Sellers:					
2	Basic Service Deferral	OS				
3	Basic Service Deferral	AD				
4	Long-Term Renewable Contract Deferrals	OS				
5	Long-Term Renewable Contract Deferrals	AD				
6	MA Renewable Portfolio Standards	OS				
7	MA Renewable Portfolio Standards	AD				
8	Net Metering Deferral	OS				
9	Residential, Commercial, Industrial					
10	and Other Nonutility Generators	OS				
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
							2
							3
15,762,796							4
95,420				8,587,773		8,587,773	5
			1,891,086		-1,200,000	691,086	6
					35,731	35,731	7
52,616				2,870,321		2,870,321	8
				1,358,570		1,358,570	9
102,538				7,259,341		7,259,341	10
				902,326		902,326	11
228,285				14,119,452		14,119,452	12
				3,670,616		3,670,616	13
80,964				7,437,053		7,437,053	14
26,630,065			1,891,086	933,685,464	123,953,609	1,059,530,159	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
113,230				9,867,881		9,867,881	1
560				35,264		35,264	2
161,451				9,525,589		9,525,589	3
				2,728,581		2,728,581	4
693,370				67,560,120		67,560,120	5
107,080				5,530,708		5,530,708	6
				3,344,790		3,344,790	7
2,796				486,468		486,468	8
77,895				4,880,116		4,880,116	9
				2,347,710		2,347,710	10
4,569,966				405,990,016		405,990,016	11
-8,330				-661,843		-661,843	12
64,552				4,200,590		4,200,590	13
				2,550,856		2,550,856	14
26,630,065			1,891,086	933,685,464	123,953,609	1,059,530,159	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
23,453				2,071,128		2,071,128	1
							2
							3
223				34,089		34,089	4
3,085				474,764		474,764	5
							6
							7
					125,468,672	125,468,672	8
					-463,964	-463,964	9
				110,133,058		110,133,058	10
478,560				89,007,329		89,007,329	11
							12
							13
							14
26,630,065			1,891,086	933,685,464	123,953,609	1,059,530,159	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
							2
							3
42				3,782	4,786	8,568	4
					15,199	15,199	5
					21,367	21,367	6
					15,073	15,073	7
							8
							9
38,621				3,074,093		3,074,093	10
2,138,149							11
454,646				35,901,943		35,901,943	12
-2,354				-166,084		-166,084	13
27,191				2,063,716		2,063,716	14
26,630,065			1,891,086	933,685,464	123,953,609	1,059,530,159	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
454,786				34,636,089		34,636,089	1
56				8,302	1,914	10,216	2
				-4	209	205	3
279				29,473	23,635	53,108	4
470,260				34,817,452		34,817,452	5
143,003				10,810,560		10,810,560	6
3,247				219,358		219,358	7
					30,987	30,987	8
							9
							10
143				6,451		6,451	11
1				180		180	12
2				42		42	13
							14
26,630,065			1,891,086	933,685,464	123,953,609	1,059,530,159	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
				-150,797		-150,797	2
				718,678		718,678	3
				3,114,093		3,114,093	4
				-490,457		-490,457	5
				28,278,528		28,278,528	6
				-503,376		-503,376	7
127,448				-4,422,965		-4,422,965	8
							9
164,035				19,423,741		19,423,741	10
							11
							12
							13
							14
26,630,065			1,891,086	933,685,464	123,953,609	1,059,530,159	

FOOTNOTE DATA

Schedule Page: 326 Line No.: 4 Column: b

Represents energy for those customers who have chosen third party suppliers. NSTAR Electric Company (East) delivers energy to these customers, but does not bear the supply costs.

Schedule Page: 326 Line No.: 5 Column: b

Boston Edison Company - Boott Mills Hydro contract.

Schedule Page: 326 Line No.: 6 Column: b

Boston Edison Company - MBTA Jet 2 contract.

Schedule Page: 326 Line No.: 9 Column: b

Short-term REC purchases.

Schedule Page: 326 Line No.: 11 Column: b

Short-term REC purchases.

Schedule Page: 326 Line No.: 13 Column: b

Short-term REC purchases.

Schedule Page: 326.1 Line No.: 4 Column: b

Short-term REC purchases.

Schedule Page: 326.1 Line No.: 7 Column: b

Short-term REC purchases.

Schedule Page: 326.1 Line No.: 8 Column: b

Borderline Service.

Schedule Page: 326.1 Line No.: 10 Column: b

Short-term REC purchases.

Schedule Page: 326.1 Line No.: 14 Column: b

Short-term REC purchases.

Schedule Page: 326.2 Line No.: 4 Column: b

Borderline Service.

Schedule Page: 326.2 Line No.: 5 Column: b

Borderline Service.

Schedule Page: 326.2 Line No.: 8 Column: b

Cumulative recovery of Basic Service costs of 2018.

Schedule Page: 326.2 Line No.: 9 Column: b

Prior years' adjustment for Recovery of Basic Service.

Schedule Page: 326.2 Line No.: 10 Column: b

Accrual for the anticipated yearly expense associated with the cost of energy procurement in compliance with the Massachusetts Renewable Portfolio Standards.

Schedule Page: 326.2 Line No.: 11 Column: b

Cumulative recovery of net metering deferral costs for 2018.

Schedule Page: 326.3 Line No.: 4 Column: b

Borderline Service.

Schedule Page: 326.3 Line No.: 5 Column: c

Connecticut Yankee Atomic Power Company rate schedule number.

Schedule Page: 326.3 Line No.: 6 Column: c

Maine Yankee Atomic Power Company rate schedule number.

Schedule Page: 326.3 Line No.: 7 Column: c

Yankee Atomic Electric Company rate schedule number.

Schedule Page: 326.3 Line No.: 11 Column: b

Represents energy for those customers who have chosen third party suppliers. NSTAR Electric Company (West) delivers energy to these customers, but does not bear the supply costs.

Schedule Page: 326.3 Line No.: 12 Column: b

Basic Service.

Schedule Page: 326.3 Line No.: 13 Column: b

Basic Service.

Schedule Page: 326.4 Line No.: 1 Column: b

Basic Service.

Schedule Page: 326.4 Line No.: 2 Column: b

Borderline Service.

Schedule Page: 326.4 Line No.: 3 Column: b

Short-term energy and capacity purchases.

Schedule Page: 326.4 Line No.: 3 Column: c

ISO New England, Inc. Transmission, Markets and Services Tariff.

Schedule Page: 326.4 Line No.: 4 Column: b

Borderline Service.

Schedule Page: 326.4 Line No.: 5 Column: b

Basic Service.

Schedule Page: 326.4 Line No.: 7 Column: b

Basic Service.

Schedule Page: 326.4 Line No.: 8 Column: c

Vermont Yankee Nuclear Power Corporation rate schedule number.

Schedule Page: 326.4 Line No.: 11 Column: b

Non-firm purchase power from Municipal Generator.

Schedule Page: 326.4 Line No.: 12 Column: b

Prior period adjustment of non-firm purchase power from Municipal Generator.

Schedule Page: 326.4 Line No.: 13 Column: b

Non-firm purchase power from Municipal Generator.

Schedule Page: 326.5 Line No.: 2 Column: b

Cumulative recovery of Basic Service costs for 2018.

Schedule Page: 326.5 Line No.: 3 Column: b

Prior years' adjustment for recovery of Basic Service.

Schedule Page: 326.5 Line No.: 4 Column: b

Cumulative recovery of Long-Term Renewable Contract Deferrals costs for 2018.

Schedule Page: 326.5 Line No.: 5 Column: b

Prior years' adjustment for Long-Term Renewable Contract Deferrals.

Schedule Page: 326.5 Line No.: 6 Column: b

Accrual for the anticipated yearly expense associated with the cost of energy procurement in compliance with the Massachusetts Renewable Portfolio Standards.

Schedule Page: 326.5 Line No.: 7 Column: b

Prior period adjustment for accrual for the anticipated yearly expense associated with the cost of energy procurement in compliance with the Massachusetts Renewable Portfolio Standards.

Schedule Page: 326.5 Line No.: 8 Column: b

Cumulative recovery of net metering deferral costs for 2018.

Schedule Page: 326.5 Line No.: 10 Column: b

This represents Residential and Commercial Nonutility Generators who generate energy and is recorded as Non-firm purchase power.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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 Classification (d)
1	NSTAR ELECTRIC COMPANY (EAST)			
2	FIRM WHEELING SERVICE			
3	Covanta Energy	Various	Covanta Energy	AD
4	Dartmouth Power Associates Limited	Dartmouth Power Associates Ltd.	ISO-NE	LFP
5	HQ Energy Services, U.S.	HQ Energy Services, US	HQ Phase I or II	OLF
6	HQ Energy Services, U.S.	HQ Energy Services, US	HQ Phase I or II	AD
7	HQ Energy Services, U.S.	HQ Energy Services, US	HQ Phase I or II	AD
8				
9	NON FIRM WHEELING SERVICE			
10	HQ Energy Services, U.S.	HQ Energy Services, US	HQ Phase I or II	NF
11	HQ Energy Services, U.S.	HQ Energy Services, US	HQ Phase I or II	AD
12	HQ Energy Services, U.S.	HQ Energy Services, US	HQ Phase I or II	AD
13				
14	NEPOOL/ISO			
15	OATT- RNS Transmission Revenue	N/A	N/A	OS
16	OATT - Scheduling & Dispatch Service	N/A	N/A	OS
17	OATT - Through or Out Service	N/A	N/A	OS
18				
19	OTHER SERVICE			
20	Belmont Municipal Light	Various	Belmont Municipal Light	AD
21	Hydro Quebec Phase II Support	Various	Various	OS
22	Hydro Quebec Phase II Support	Various	Various	AD
23	Hydro Quebec Phase II Support	Associated Utility	Various	OS
24	Hydro Quebec Phase II Support	Associated Utility	Various	AD
25	New England Power Lines 255-2337/2338	Various	Various	OS
26	New England Power Lines 255-2337/2338	Various	Various	AD
27	Concord Municipal Light-Wellesley	Various	Various	OS
28	Concord Municipal Light-Wellesley	Various	Various	AD
29	National Grid-Dewar Street	Various	Various	OS
30	National Grid-Dewar Street	Various	Various	AD
31	ANP Blackstone Energy Co.	Various	Various	OS
32	ANP Blackstone Energy Co.	Various	Various	AD
33	Granite Ridge Energy, LLC	Various	Various	OS
34	Granite Ridge Energy, LLC	Various	Various	AD
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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 Classification (d)
1	New England Power-Merchants Way	Various	Various	OS
2	New England Power-Merchants Way	Various	Various	AD
3	Millennium Power Partners, L.P.	Various	Various	OS
4	Millennium Power Partners, L.P.	Various	Various	AD
5	Constellation Mystic Power, LLC	Various	Various	OS
6	Calpine Fore River Energy Center, LLC	Various	Various	OS
7	Calpine Fore River Energy Center, LLC	Various	Various	AD
8	Gen On Kendall, LLC	Kendall Station	Various	OS
9	Gen On Kendall, LLC	Kendall Station	Various	AD
10	Entergy Nuclear Generation Co.	Various	Entergy Nuclear Generation Co.	OS
11	Entergy Nuclear Generation Co.	Various	Entergy Nuclear Generation Co.	AD
12	National Grid-Edgar Station	Various	Various	OS
13	Nalcor Energy Marketing Corporation	N/A	N/A	OS
14				
15	NETWORK SERVICE			
16	Massachusetts Bay Transportation Authority	Various	Massachusetts Bay Transportation	FNO
17	Massachusetts Bay Transportation Authority	Various	Massachusetts Bay Transportation	AD
18	Concord Municipal Light-LNS	Various	Concord Municipal Light	FNO
19	Concord Municipal Light-LNS	Various	Concord Municipal Light	AD
20	Massachusetts Port Authority	Various	Massachusetts Port Authority	FNO
21	Massachusetts Port Authority	Various	Massachusetts Port Authority	AD
22	National Grid-Nantucket Cable	Various	National Grid	FNO
23	National Grid-Nantucket Cable	Various	National Grid	AD
24	NSTAR Electric Company (East)	Associated Utility	NSTAR Electric Company (East)	FNS
25				
26				
27				
28	NSTAR ELECTRIC COMPANY (WEST)			
29	FIRM WHEELING SERVICE			
30	Essential Power Massachusetts, LLC	Essential Power Massachusetts,LLC	Various	LFP
31	HQ Energy Services, U.S.	HQ Energy Services, U.S.	HQ Phase I or II	OLF
32	NRG Energy, Inc.	NRG Energy, Inc.	NEPOOL PTF	LFP
33				
34	NON-FIRM WHEELING SERVICE			
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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 Classification (d)
1	Algonquin Windsor Locks, LLC	Algonquin Windsor Locks, LLC	NEPOOL PTF	NF
2	Algonquin Windsor Locks, LLC	Algonquin Windsor Locks, LLC	NEPOOL PTF	AD
3	Brookfield Energy Marketing LP - Berlin	Brookfield Energy Marketing LP	NEPOOL PTF	NF
4	Brookfield Energy Marketing LP - Berlin	Brookfield Energy Marketing LP	NEPOOL PTF	AD
5	Brookfield Energy Marketing LP - Pontook	Brookfield Energy Marketing LP	NEPOOL PTF	NF
6	Brookfield Energy Marketing LP - Pontook	Brookfield Energy Marketing LP	NEPOOL PTF	AD
7	Brookfield Energy Marketing LP-HQ	Brookfield Energy Marketing LP-HQ	HQ Phase I or II	NF
8	Covanta Energy Marketing, LLC	Covanta Energy Marketing, LLC	NEPOOL PTF	NF
9	Covanta Energy Marketing, LLC	Covanta Energy Marketing, LLC	NEPOOL PTF	AD
10	Covanta Springfield, LLC	Covanta Springfield, LLC	NEPOOL PTF	NF
11	Covanta Springfield, LLC	Covanta Springfield, LLC	NEPOOL PTF	AD
12	Essential Power Massachusetts, LLC	Essential Power Massachusetts,LLC	NEPOOL PTF	NF
13	Essential Power Massachusetts, LLC	Essential Power Massachusetts,LLC	NEPOOL PTF	AD
14	FirstLight Power Resources, Inc.	FirstLight Power Resources, Inc	NEPOOL PTF	NF
15	FirstLight Power Resources, Inc.	FirstLight Power Resources, Inc.	NEPOOL PTF	AD
16	FirstLight Power Resources Management	FirstLight Power Resources	NEPOOL PTF	NF
17	FirstLight Power Resources Management	FirstLight Power Resources	NEPOOL PTF	AD
18	Granite Reliable Power, LLC	Granite Reliable Power, LLC	NEPOOL PTF	NF
19	Granite Reliable Power, LLC	Granite Reliable Power, LLC	NEPOOL PTF	AD
20	GSP Newington, LLC	GSP Newington, LLC	NEPOOL PTF	NF
21	GSP Lost Nation, LLC	GSP Lost Nation, LLC	NEPOOL PTF	NF
22	HSE Hydro NH Canaan, LLC	HSE Hydro NH Canaan, LLC	NEPOOL PTF	NF
23	HSE Hydro NH Gorham, LLC	HSE Hydro NH Gorham, LLC	NEPOOL PTF	NF
24	HSE Hyrdro NH Smith, LLC	HSE Hyrdro NH Smith, LLC	NEPOOL PTF	NF
25	Jericho Power, LLC	Jericho Power, LLC	NEPOOL PTF	NF
26	Jericho Power, LLC	Jericho Power, LLC	NEPOOL PTF	AD
27	Messalonskee Stream Hydro, LLC	Messalonskee Stream Hydro, LLC	NEPOOL PTF	NF
28	Messalonskee Stream Hydro, LLC	Messalonskee Stream Hydro, LLC	NEPOOL PTF	AD
29	Pittsfield Generating Company, LP	Pittsfield Generating Company, LP	NEPOOL PTF	NF
30	Pittsfield Generating Company, LP	Pittsfield Generating Company, LP	NEPOOL PTF	AD
31	Plainfield Renewable Energy, LLC	Plainfield Renewable Energy, LLC	NEPOOL PTF	NF
32	Plainfield Renewable Energy, LLC	Plainfield Renewable Energy, LLC	NEPOOL PTF	AD
33	Power Supply Services, LLC	Power Supply Services, LLC	NEPOOL PTF	NF
34	Power Supply Services, LLC	Power Supply Services, LLC	NEPOOL PTF	AD
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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 Classification (d)
1	The Springfield Water and Sewer	The Springfield Water and Sewer	NEPOOL PTF	NF
2	The Springfield Water and Sewer	The Springfield Water and Sewer	NEPOOL PTF	AD
3	Sterling Light Department	Sterling Light Department	NEPOOL PTF	NF
4	Sterling Light Department	Sterling Light Department	NEPOOL PTF	AD
5	Sterling Municipal Light Department	Sterling Municipal Light Depart	NEPOOL PTF	NF
6	Sterling Municipal Light Department	Sterling Municipal Light Depart	NEPOOL PTF	AD
7	Waterbury Generation, LLC	Waterbury Generation, LLC	NEPOOL PTF	NF
8	Waterbury Generation, LLC	Waterbury Generation, LLC	NEPOOL PTF	AD
9	Woods Hill Solar, LLC	Woods Hill Solar, LLC	NEPOOL PTF	NF
10				
11	TRANSMISSION SUPPORT			
12	Massachusetts Municipal Wholesale Elec.	Not Applicable	Not Applicable	OS
13				
14	NEPOOL/ISO			
15	OATT - Regional Network Service	Not Applicable	Not Applicable	OS
16	OATT - Scheduling & Dispatch Service	Not Applicable	Not Applicable	OS
17	OATT - Through or Out Service	Not Applicable	Not Applicable	OS
18				
19	OTHER SERVICE			
20	Shared Microwave Transmission Revenue	Not Applicable	Not Applicable	OS
21	Ashburnham Municipal Light Department	Not Applicable	Not Applicable	OS
22	Ashburnham Municipal Light Department	Not Applicable	Not Applicable	AD
23	Belmont Municipal Light Department	Not Applicable	Not Applicable	OS
24	Belmont Municipal Light Department	Not Applicable	Not Applicable	AD
25	Boylston Municipal Light Department	Not Applicable	Not Applicable	OS
26	Braintree Electric Light Department	Not Applicable	Not Applicable	OS
27	Braintree Electric Light Department	Not Applicable	Not Applicable	AD
28	Chicopee Municipal Lighting Plant	Not Applicable	Not Applicable	OS
29	Chicopee Municipal Lighting Plant	Not Applicable	Not Applicable	AD
30	Concord Municipal Light Plant	Not Applicable	Not Applicable	OS
31	Concord Municipal Light Plant	Not Applicable	Not Applicable	AD
32	Danvers Electric Division	Not Applicable	Not Applicable	OS
33	Danvers Electric Division	Not Applicable	Not Applicable	AD
34	Fitchburg Gas and Electric Light	Not Applicable	Not Applicable	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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 Classification (d)
1	Fitchburg Gas and Electric Light	Not Applicable	Not Applicable	AD
2	Georgetown Municipal Light Department	Not Applicable	Not Applicable	OS
3	Georgetown Municipal Light Department	Not Applicable	Not Applicable	AD
4	Groton Electric Light Department	Not Applicable	Not Applicable	OS
5	Groton Electric Light Department	Not Applicable	Not Applicable	AD
6	Groveland Electric Light Department	Not Applicable	Not Applicable	OS
7	Groveland Electric Light Department	Not Applicable	Not Applicable	AD
8	Hingham Municipal Lighting Plant	Not Applicable	Not Applicable	OS
9	Hingham Municipal Lighting Plant	Not Applicable	Not Applicable	AD
10	Holden Municipal Light Department	Not Applicable	Not Applicable	OS
11	Holden Municipal Light Department	Not Applicable	Not Applicable	AD
12	Holyoke Gas & Electric Department	Not Applicable	Not Applicable	OS
13	Holyoke Gas & Electric Department	Not Applicable	Not Applicable	AD
14	Hudson Light & Power Department	Not Applicable	Not Applicable	OS
15	Hudson Light & Power Department	Not Applicable	Not Applicable	AD
16	Hull Municipal Lighting Plant	Not Applicable	Not Applicable	OS
17	Hull Municipal Lighting Plant	Not Applicable	Not Applicable	AD
18	Ipswich Municipal Light Department	Not Applicable	Not Applicable	OS
19	Ipswich Municipal Light Department	Not Applicable	Not Applicable	AD
20	Littleton Electric Light & Water	Not Applicable	Not Applicable	OS
21	Littleton Electric Light & Water	Not Applicable	Not Applicable	AD
22	Mansfield Municipal Electric Light	Not Applicable	Not Applicable	OS
23	Mansfield Municipal Electric Light	Not Applicable	Not Applicable	AD
24	Marblehead Municipal Light Department	Not Applicable	Not Applicable	OS
25	Marblehead Municipal Light Department	Not Applicable	Not Applicable	AD
26	Massachusetts Bay Transportation Authority	Not Applicable	Not Applicable	OS
27	Massachusetts Bay Transportation Authority	Not Applicable	Not Applicable	AD
28	Massachusetts Development Finance Agency	Not Applicable	Not Applicable	OS
29	Massachusetts Development Finance Agency	Not Applicable	Not Applicable	AD
30	Massachusetts Electric Company	Not Applicable	Not Applicable	OS
31	Massachusetts Electric Company	Not Applicable	Not Applicable	AD
32	Massachusetts Port Authority	Not Applicable	Not Applicable	OS
33	Massachusetts Port Authority	Not Applicable	Not Applicable	AD
34	MATEP, LLC	Not Applicable	Not Applicable	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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 Classification (d)
1	MATEP, LLC	Not Applicable	Not Applicable	AD
2	Merrimac Municipal Light Plant	Not Applicable	Not Applicable	OS
3	Middleborough Gas & Electric Division	Not Applicable	Not Applicable	OS
4	Middleborough Gas & Electric Division	Not Applicable	Not Applicable	AD
5	Middleton Municipal Light Department	Not Applicable	Not Applicable	OS
6	Middleton Municipal Light Department	Not Applicable	Not Applicable	AD
7	New England Power Company	Not Applicable	Not Applicable	OS
8	New England Power Company	Not Applicable	Not Applicable	AD
9	North Attleborough Electric Department	Not Applicable	Not Applicable	OS
10	North Attleborough Electric Department	Not Applicable	Not Applicable	AD
11	Norwood Municipal Light Department	Not Applicable	Not Applicable	OS
12	Norwood Municipal Light Department	Not Applicable	Not Applicable	AD
13	Paxton Municipal Light Department	Not Applicable	Not Applicable	OS
14	Paxton Municipal Light Department	Not Applicable	Not Applicable	AD
15	Peabody Municipal Light Plant	Not Applicable	Not Applicable	OS
16	Peabody Municipal Light Plant	Not Applicable	Not Applicable	AD
17	Princeton Municipal Light Department	Not Applicable	Not Applicable	OS
18	Reading Municipal Light Department	Not Applicable	Not Applicable	OS
19	Reading Municipal Light Department	Not Applicable	Not Applicable	AD
20	Rowley Municipal Lighting Plant	Not Applicable	Not Applicable	OS
21	Rowley Municipal Lighting Plant	Not Applicable	Not Applicable	AD
22	Russell Municipal Light Department	Not Applicable	Not Applicable	OS
23	Russell Municipal Light Department	Not Applicable	Not Applicable	AD
24	Shrewsbury Electric Light Plant	Not Applicable	Not Applicable	OS
25	Shrewsbury Electric Light Plant	Not Applicable	Not Applicable	AD
26	South Hadley Electric Light Department	Not Applicable	Not Applicable	OS
27	South Hadley Electric Light Department	Not Applicable	Not Applicable	AD
28	Sterling Municipal Electric Light	Not Applicable	Not Applicable	OS
29	Sterling Municipal Electric Light	Not Applicable	Not Applicable	AD
30	Taunton Municipal Lighting Plant	Not Applicable	Not Applicable	OS
31	Taunton Municipal Lighting Plant	Not Applicable	Not Applicable	AD
32	Templeton Municipal Lighting Plant	Not Applicable	Not Applicable	OS
33	Templeton Municipal Lighting Plant	Not Applicable	Not Applicable	AD
34	Wakefield Municipal Gas & Light	Not Applicable	Not Applicable	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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 Classification (d)
1	Wakefield Municipal Gas & Light	Not Applicable	Not Applicable	AD
2	Wellesley Municipal Light Plant	Not Applicable	Not Applicable	OS
3	Wellesley Municipal Light Plant	Not Applicable	Not Applicable	AD
4	West Boylston Municipal Lighting Plant	Not Applicable	Not Applicable	OS
5	West Boylston Municipal Lighting Plant	Not Applicable	Not Applicable	AD
6	Westfield Gas & Electric Light Department	Not Applicable	Not Applicable	OS
7	Westfield Gas & Electric Light Department	Not Applicable	Not Applicable	AD
8	Chester Municipal Electric Light Department	Not Applicable	Not Applicable	OS
9	Chester Municipal Electric Light Department	Not Applicable	Not Applicable	AD
10				
11	NETWORK SERVICE			
12	Ashland Municipal Electric Department	Various	Ashland Municipal Electric Dept.	FNO
13	Ashland Municipal Electric Department	Various	Ashland Municipal Electric Dept.	AD
14	The Connecticut Light & Power Company	Associated Utility	The Connecticut Light & Power Co.	FNO
15	The Connecticut Light & Power Company	Associated Utility	The Connecticut Light & Power Co.	AD
16	CT Transmission Municipal Electric Energy	Various New England Utilities	CT Transmission Municipal Elec	FNO
17	CT Transmission Municipal Electric Energy	Various New England Utilities	CT Transmission Municipal Elec	AD
18	GenConn Energy, LLC	Various	GenConn Energy, LLC	FNO
19	GenConn Energy, LLC	Various	GenConn Energy, LLC	AD
20	New England Power Company	New England Power	New England Power Company	FNO
21	New England Power Company	New England Power	New England Power Company	AD
22	New Hampshire Electric Co-op.	Various New England Utilities	New Hampshire Electric Co-op.	FNO
23	New Hampshire Electric Co-op.	Various New England Utilities	New Hampshire Electric Co-op.	AD
24	Public Service Company of New Hampshire	Associated Utility	Public Service Company of NH	FNO
25	Public Service Company of New Hampshire	Associated Utility	Public Service Company of NH	AD
26	Unitil Energy Systems, Inc.	Various	Unitil Energy Systems, Inc.	FNO
27	Unitil Energy Systems, Inc.	Various	Unitil Energy Systems, Inc.	AD
28	Waterbury Generation, LLC	Waterbury Generation, LLC	Waterbury Generation, LLC	FNO
29	Waterbury Generation, LLC	Waterbury Generation, LLC	Waterbury Generation, LLC	AD
30	NSTAR Electric Company (West)	Associated Utility	NSTAR Electric Company (West)	FNS
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
						1
						2
ISO-NE OATT	Station 718	Covanta				3
Negotiated	NSTAR LINE 111	High Hill Substation		66,857	66,857	4
ISO-NE OATT	NE HVDC Border	HQ Phase I or II		1,521,202	1,521,202	5
ISO-NE OATT	NE HVDC Border	HQ Phase I or II				6
ISO-NE-OATT	NE HVDC Border	HQ Phase I or II				7
						8
						9
ISO-NE OATT	NE HVDC Border	HQ Phase I or II		308,281	308,281	10
ISO-NE OATT	NE HVDC Border	HQ Phase I or II				11
ISO-NE OATT	NE HVDC Border	HQ Phase I or II				12
						13
						14
ISO-NE OATT	N/A	N/A				15
ISO-NE OATT	N/A	N/A				16
ISO-NE OATT	N/A	N/A				17
						18
						19
36	Station 509	NSTAR System				20
Support	Various	Various				21
Support	Various	Various				22
Support	Various	Various				23
Support	Various	Various				24
Support	Various	Various				25
Support	Various	Various				26
Support	Various	Concord/Wellesley				27
Support	Various	Concord/Wellesley				28
Support	Various	Various				29
Support	Various	Various				30
Tariff Vol. 3-IA	N/A	N/A				31
Tariff Vol. 3-IA	N/A	N/A				32
Tariff Vol. 3-IA	N/A	N/A				33
Tariff Vol. 3-IA	N/A	N/A				34
			0	**28,794,602**	**28,794,602**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
Tariff Vol. 3-IA	N/A	N/A				1
Tariff Vol. 3-IA	N/A	N/A				2
Tariff Vol. 3-IA	N/A	N/A				3
Tariff Vol. 3-IA	N/A	N/A				4
Tariff Vol. 3-IA	N/A	N/A				5
Tariff Vol. 3-IA	N/A	N/A				6
Tariff Vol. 3-IA	N/A	N/A				7
Tariff Vol. 3-IA	Kendall Station	Various				8
Tariff Vol. 3-IA	Kendall Station	Various				9
Tariff Vol. 3-IA	Manomet Station	Pole #178				10
Tariff Vol. 3-IA	Manomet Station	Pole #178				11
Tariff Vol. 3-IA	N/A	N/A				12
Negotiated	N/A	N/A				13
						14
						15
ISO-NE OATT	Various	MBTA		347,635	347,635	16
ISO-NE OATT	Various	MBTA				17
ISO-NE OATT	Various	Concord		167,775	167,775	18
ISO-NE OATT	Various	Concord				19
ISO-NE OATT	Various	MASSPORT		208,255	208,255	20
ISO-NE OATT	Various	MASSPORT				21
ISO-NE OATT	Commonwealth	Lothrop Station		188,566	188,566	22
ISO-NE OATT	Commonwealth	Lothrop Station				23
ISO-NE OATT	Various	NSTAR East System		21,142,456	21,142,456	24
						25
						26
						27
						28
						29
ISO-NE OATT	Various	EVERSOURCE PTF		16,263	16,263	30
ISO-NE OATT	NE HVDC Border	HQ Phase I or II		501,331	501,331	31
ISO-NE OATT	Middletown 345 KV	NEPOOL PTF				32
						33
						34
			0	**28,794,602**	**28,794,602**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
ISO-NE OATT	Windsor Locks Sub	NEPOOL PTF				1
ISO-NE OATT	Windsor Locks Sub	NEPOOL PTF				2
ISO-NE OATT	Berlin Substation	NEPOOL PTF				3
ISO-NE OATT	Berlin Substation	NEPOOL PTF				4
ISO-NE OATT	Pontook Substation	NEPOOL PTF				5
ISO-NE OATT	Pontook Substation	NEPOOL PTF				6
ISO-NE OATT	NE HVDC Border	HQ Phase I or II		30	30	7
ISO-NE OATT	Hallville Substation	NEPOOL PTF				8
ISO-NE OATT	Hallville Substation	NEPOOL PTF				9
ISO-NE OATT	West Springfield Sub	NEPOOL PTF		39,327	39,327	10
ISO-NE OATT	West Springfield Sub	NEPOOL PTF				11
ISO-NE OATT	West Springfield Sub	NEPOOL PTF		3,050	3,050	12
ISO-NE OATT	West Springfield Sub	NEPOOL PTF				13
ISO-NE OATT	Various	NEPOOL PTF				14
ISO-NE OATT	Various	NEPOOL PTF				15
ISO-NE OATT	French King Sub	NEPOOL PTF		1,724	1,724	16
ISO-NE OATT	French King Sub	NEPOOL PTF				17
ISO-NE OATT	Paris Substation	NEPOOL PTF				18
ISO-NE OATT	Paris Substation	NEPOOL PTF				19
ISO-NE OATT	POCO on 115 KV lines	NEPOOL PTF				20
ISO-NE OATT	Lost Nation Subst	NEPOOL PTF				21
ISO-NE OATT	POCO on 34.5kV line	NEPOOL PTF				22
ISO-NE OATT	POCO on 34.5kV line	NEPOOL PTF				23
ISO-NE OATT	POCO on 115KV lines	NEPOOL PTF				24
ISO-NE OATT	Berlin Substation	NEPOOL PTF				25
ISO-NE OATT	Berlin Substation	NEPOOL PTF				26
ISO-NE-OATT	Long Hill SS	NEPOOL PTF				27
ISO-NE-OATT	Long Hill SS	NEPOOL PTF				28
ISO-NE OATT	Pittsfield Sub	NEPOOL PTF		117,976	117,976	29
ISO-NE OATT	Pittsfield Sub	NEPOOL PTF				30
ISO-NE OATT	Fry Brook Substation	NEPOOL PTF				31
ISO-NE OATT	Fry Brook Substation	NEPOOL PTF				32
ISO-NE OATT	Laconia & Longhill	NEPOOL PTF				33
ISO-NE OATT	Laconia & Longhill	NEPOOL PTF				34
			0	**28,794,602**	**28,794,602**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
ISO-NE OATT	Cobble Mt.	NEPOOL PTF		29,159	29,159	1
ISO-NE OATT	Cobble Mt.	NEPOOL PTF				2
ISO-NE OATT	Tracy Substation	NEPOOL PTF				3
ISO-NE OATT	Tracy Substation	NEPOOL PTF				4
ISO-NE OATT	Tracy Substation	NEPOOL PTF				5
ISO-NE OATT	Tracy Substation	NEPOOL PTF				6
ISO-NE OATT	Baldwin Substation	NEPOOL PTF				7
ISO-NE OATT	Baldwin Substation	NEPOOL PTF				8
ISO-NE OATT	Tracy Substation	NEPOOL PTF				9
						10
						11
407	Not Applicable	Not Applicable				12
						13
						14
ISO-NE OATT	Not Applicable	Not Applicable				15
ISO-NE OATT	Not Applicable	Not Applicable				16
ISO-NE OATT	Not Applicable	Not Applicable				17
						18
						19
ISO-NE OATT	Not Applicable	Not Applicable				20
ISO-NE OATT	Not Applicable	Not Applicable				21
ISO-NE OATT	Not Applicable	Not Applicable				22
ISO-NE OATT	Not Applicable	Not Applicable				23
ISO-NE OATT	Not Applicable	Not Applicable				24
ISO-NE OATT	Not Applicable	Not Applicable				25
ISO-NE OATT	Not Applicable	Not Applicable				26
ISO-NE OATT	Not Applicable	Not Applicable				27
ISO-NE OATT	Not Applicable	Not Applicable				28
ISO-NE OATT	Not Applicable	Not Applicable				29
ISO-NE OATT	Not Applicable	Not Applicable				30
ISO-NE OATT	Not Applicable	Not Applicable				31
ISO-NE OATT	Not Applicable	Not Applicable				32
ISO-NE OATT	Not Applicable	Not Applicable				33
ISO-NE OATT	Not Applicable	Not Applicable				34
			0	**28,794,602**	**28,794,602**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
ISO-NE OATT	Not Applicable	Not Applicable				1
ISO-NE OATT	Not Applicable	Not Applicable				2
ISO-NE OATT	Not Applicable	Not Applicable				3
ISO-NE OATT	Not Applicable	Not Applicable				4
ISO-NE OATT	Not Applicable	Not Applicable				5
ISO-NE OATT	Not Applicable	Not Applicable				6
ISO-NE OATT	Not Applicable	Not Applicable				7
ISO-NE OATT	Not Applicable	Not Applicable				8
ISO-NE OATT	Not Applicable	Not Applicable				9
ISO-NE OATT	Not Applicable	Not Applicable				10
ISO-NE OATT	Not Applicable	Not Applicable				11
ISO-NE OATT	Not Applicable	Not Applicable				12
ISO-NE OATT	Not Applicable	Not Applicable				13
ISO-NE OATT	Not Applicable	Not Applicable				14
ISO-NE OATT	Not Applicable	Not Applicable				15
ISO-NE OATT	Not Applicable	Not Applicable				16
ISO-NE OATT	Not Applicable	Not Applicable				17
ISO-NE OATT	Not Applicable	Not Applicable				18
ISO-NE OATT	Not Applicable	Not Applicable				19
ISO-NE OATT	Not Applicable	Not Applicable				20
ISO-NE OATT	Not Applicable	Not Applicable				21
ISO-NE OATT	Not Applicable	Not Applicable				22
ISO-NE OATT	Not Applicable	Not Applicable				23
ISO-NE OATT	Not Applicable	Not Applicable				24
ISO-NE OATT	Not Applicable	Not Applicable				25
ISO-NE OATT	Not Applicable	Not Applicable				26
ISO-NE OATT	Not Applicable	Not Applicable				27
ISO-NE OATT	Not Applicable	Not Applicable				28
ISO-NE OATT	Not Applicable	Not Applicable				29
ISO-NE OATT	Not Applicable	Not Applicable				30
ISO-NE OATT	Not Applicable	Not Applicable				31
ISO-NE OATT	Not Applicable	Not Applicable				32
ISO-NE OATT	Not Applicable	Not Applicable				33
ISO-NE OATT	Not Applicable	Not Applicable				34
			0	**28,794,602**	**28,794,602**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
ISO-NE OATT	Not Applicable	Not Applicable				1
ISO-NE OATT	Not Applicable	Not Applicable				2
ISO-NE OATT	Not Applicable	Not Applicable				3
ISO-NE OATT	Not Applicable	Not Applicable				4
ISO-NE OATT	Not Applicable	Not Applicable				5
ISO-NE OATT	Not Applicable	Not Applicable				6
ISO-NE OATT	Not Applicable	Not Applicable				7
ISO-NE OATT	Not Applicable	Not Applicable				8
ISO-NE OATT	Not Applicable	Not Applicable				9
ISO-NE OATT	Not Applicable	Not Applicable				10
ISO-NE OATT	Not Applicable	Not Applicable				11
ISO-NE OATT	Not Applicable	Not Applicable				12
ISO-NE OATT	Not Applicable	Not Applicable				13
ISO-NE OATT	Not Applicable	Not Applicable				14
ISO-NE OATT	Not Applicable	Not Applicable				15
ISO-NE OATT	Not Applicable	Not Applicable				16
ISO-NE OATT	Not Applicable	Not Applicable				17
ISO-NE OATT	Not Applicable	Not Applicable				18
ISO-NE OATT	Not Applicable	Not Applicable				19
ISO-NE OATT	Not Applicable	Not Applicable				20
ISO-NE OATT	Not Applicable	Not Applicable				21
ISO-NE OATT	Not Applicable	Not Applicable				22
ISO-NE OATT	Not Applicable	Not Applicable				23
ISO-NE OATT	Not Applicable	Not Applicable				24
ISO-NE OATT	Not Applicable	Not Applicable				25
ISO-NE OATT	Not Applicable	Not Applicable				26
ISO-NE OATT	Not Applicable	Not Applicable				27
ISO-NE OATT	Not Applicable	Not Applicable				28
ISO-NE OATT	Not Applicable	Not Applicable				29
ISO-NE OATT	Not Applicable	Not Applicable				30
ISO-NE OATT	Not Applicable	Not Applicable				31
ISO-NE OATT	Not Applicable	Not Applicable				32
ISO-NE OATT	Not Applicable	Not Applicable				33
ISO-NE OATT	Not Applicable	Not Applicable				34
			0	**28,794,602**	**28,794,602**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
ISO-NE OATT	Not Applicable	Not Applicable				1
ISO-NE OATT	Not Applicable	Not Applicable				2
ISO-NE OATT	Not Applicable	Not Applicable				3
ISO-NE OATT	Not Applicable	Not Applicable				4
ISO-NE OATT	Not Applicable	Not Applicable				5
ISO-NE OATT	Not Applicable	Not Applicable				6
ISO-NE OATT	Not Applicable	Not Applicable				7
ISO-NE OATT	Not Applicable	Not Applicable				8
ISO-NE OATT	Not Applicable	Not Applicable				9
						10
						11
ISO-NE OATT	Various	Ashland Substation				12
ISO-NE OATT	Various	Ashland Substation				13
ISO-NE OATT	Various	CL&P System				14
ISO-NE OATT	Various	CL&P System				15
ISO-NE OATT	Various	CTMEEC System				16
ISO-NE OATT	Various	CTMEEC System				17
ISO-NE OATT	Various	GenConn System				18
ISO-NE OATT	Various	GenConn System				19
ISO-NE OATT	NEPCO System	Various		507,172	507,172	20
ISO-NE OATT	NEPCO System	Various				21
ISO-NE OATT	Border of ES System	New Hampshire Co-op.				22
ISO-NE OATT	Border of ES System	New Hampshire Co-op.				23
ISO-NE OATT	Various	PSNH System				24
ISO-NE OATT	Various	PSNH System				25
ISO-NE OATT	Various	Unitil System				26
ISO-NE OATT	Various	Unitil System				27
ISO-NE OATT	Various	Baldwin Substation				28
ISO-NE OATT	Various	Baldwin Substation				29
ISO-NE OATT	Various	NSTAR West System		3,627,543	3,627,543	30
						31
						32
						33
						34
			0	**28,794,602**	**28,794,602**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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.
				1
				2
		-21,140	-21,140	3
		297,432	297,432	4
		2,671,204	2,671,204	5
		-126,961	-126,961	6
		-14,858	-14,858	7
				8
				9
		1,780,802	1,780,802	10
		-84,641	-84,641	11
		-9,906	-9,906	12
				13
				14
		259,753,394	259,753,394	15
		7,095,439	7,095,439	16
		430,505	430,505	17
				18
				19
		2,271	2,271	20
		208,935	208,935	21
		-6,835	-6,835	22
		115,055	115,055	23
		-3,763	-3,763	24
		2,619	2,619	25
		-454	-454	26
		66,400	66,400	27
		1,930	1,930	28
		649,800	649,800	29
		-55,087	-55,087	30
		616,600	616,600	31
		-27,140	-27,140	32
		12,500	12,500	33
		-993	-993	34
0	**0**	**367,750,994**	**367,750,994**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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.
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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.
		60,700	60,700	1
		-449	-449	2
		20,400	20,400	3
		-808	-808	4
		1,100,004	1,100,004	5
		258,200	258,200	6
		-4,412	-4,412	7
		435,900	435,900	8
		-24,117	-24,117	9
		25,900	25,900	10
		234	234	11
		85,897	85,897	12
		27,400	27,400	13
				14
				15
		462,087	462,087	16
		-41,653	-41,653	17
		91,703	91,703	18
		-10,562	-10,562	19
		593,386	593,386	20
		-58,974	-58,974	21
		290,117	290,117	22
		-29,599	-29,599	23
				24
				25
				26
				27
				28
				29
				30
		1,635,131	1,635,131	31
		449,691	449,691	32
				33
				34
0	**0**	**367,750,994**	**367,750,994**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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.
		41,726	41,726	1
		2,121	2,121	2
		20,563	20,563	3
		3,581	3,581	4
		24,116	24,116	5
		2,173	2,173	6
		32	32	7
		50,774	50,774	8
		1,942	1,942	9
		19,181	19,181	10
		1,806	1,806	11
		2,776	2,776	12
		306	306	13
		136,535	136,535	14
		9,547	9,547	15
		897	897	16
		103	103	17
		106,835	106,835	18
		9,388	9,388	19
		5,501	5,501	20
		198	198	21
		1,004	1,004	22
		2,329	2,329	23
		18,363	18,363	24
		12,081	12,081	25
		1,232	1,232	26
		7,482	7,482	27
		131	131	28
		71,199	71,199	29
		9,106	9,106	30
		24,595	24,595	31
		1,749	1,749	32
		2,605	2,605	33
		713	713	34
0	**0**	**367,750,994**	**367,750,994**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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.
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REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		18,871	18,871	1
		617	617	2
		672	672	3
		52	52	4
		257	257	5
		26	26	6
		1,429	1,429	7
		1,468	1,468	8
		12,984	12,984	9
				10
				11
		68,544	68,544	12
				13
				14
		70,178,265	70,178,265	15
		1,826	1,826	16
		249,750	249,750	17
				18
				19
		100,116	100,116	20
		638	638	21
		-1	-1	22
		2,631	2,631	23
		-23	-23	24
		691	691	25
		7,397	7,397	26
		-30	-30	27
		9,517	9,517	28
		-41	-41	29
		3,656	3,656	30
		-11	-11	31
		6,571	6,571	32
		-34	-34	33
		8,988	8,988	34
0	**0**	**367,750,994**	**367,750,994**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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.
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REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		-41	-41	1
		1,074	1,074	2
		-2	-2	3
		1,582	1,582	4
		-10	-10	5
		822	822	6
		-3	-3	7
		4,522	4,522	8
		-24	-24	9
		2,404	2,404	10
		-10	-10	11
		6,845	6,845	12
		-27	-27	13
		4,669	4,669	14
		-19	-19	15
		977	977	16
		-5	-5	17
		2,448	2,448	18
		-6	-6	19
		4,872	4,872	20
		-27	-27	21
		4,394	4,394	22
		-21	-21	23
		2,449	2,449	24
		-14	-14	25
		7,064	7,064	26
		-27	-27	27
		2,704	2,704	28
		-14	-14	29
		394,794	394,794	30
		-1,734	-1,734	31
		3,427	3,427	32
		-13	-13	33
		1,633	1,633	34
0	**0**	**367,750,994**	**367,750,994**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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.
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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.
		-14	-14	1
		634	634	2
		5,421	5,421	3
		-21	-21	4
		2,027	2,027	5
		-12	-12	6
		28,342	28,342	7
		-101	-101	8
		5,055	5,055	9
		-21	-21	10
		6,521	6,521	11
		-32	-32	12
		525	525	13
		2	2	14
		10,324	10,324	15
		-48	-48	16
		343	343	17
		13,775	13,775	18
		-68	-68	19
		1,001	1,001	20
		-2	-2	21
		103	103	22
		-8	-8	23
		5,974	5,974	24
		-19	-19	25
		2,529	2,529	26
		-6	-6	27
		941	941	28
		1	1	29
		13,131	13,131	30
		-55	-55	31
		1,073	1,073	32
		-6	-6	33
		3,953	3,953	34
0	**0**	**367,750,994**	**367,750,994**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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.
		-18	-18	1
		5,609	5,609	2
		-29	-29	3
		1,190	1,190	4
		-6	-6	5
		7,326	7,326	6
		-37	-37	7
		116	116	8
		-7	-7	9
				10
				11
		8,161	8,161	12
		738	738	13
		10,626,755	10,626,755	14
		943,581	943,581	15
		376,902	376,902	16
		34,134	34,134	17
		19,663	19,663	18
		4,507	4,507	19
		231,459	231,459	20
		20,561	20,561	21
		345,417	345,417	22
		31,093	31,093	23
		3,596,594	3,596,594	24
		323,764	323,764	25
		588,470	588,470	26
		52,137	52,137	27
		129	129	28
		40	40	29
				30
				31
				32
				33
				34
0	**0**	**367,750,994**	**367,750,994**	

Schedule Page: 328 Line No.: 3 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328 Line No.: 6 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328 Line No.: 7 Column: m
This relates to a 2012 True-up adjustment.

Schedule Page: 328 Line No.: 11 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328 Line No.: 12 Column: m
This relates to a 2012 True-up adjustment.

Schedule Page: 328 Line No.: 22 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328 Line No.: 24 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328 Line No.: 26 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328 Line No.: 28 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328 Line No.: 30 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328 Line No.: 32 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328 Line No.: 34 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328.1 Line No.: 2 Column: m
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Schedule Page: 328.1 Line No.: 4 Column: m
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Schedule Page: 328.1 Line No.: 7 Column: m
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Schedule Page: 328.1 Line No.: 9 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328.1 Line No.: 11 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328.1 Line No.: 17 Column: m
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Schedule Page: 328.1 Line No.: 19 Column: m
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Schedule Page: 328.1 Line No.: 21 Column: m
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Schedule Page: 328.1 Line No.: 23 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328.1 Line No.: 24 Column: m
Intracompany revenues are not reported on the FERC form.

Schedule Page: 328.2 Line No.: 2 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328.2 Line No.: 4 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328.2 Line No.: 6 Column: m
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Schedule Page: 328.2 Line No.: 9 Column: m

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Schedule Page: 328.3 Line No.: 31 Column: m

This relates to the 2017 Annual True-up.

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FOOTNOTE DATA

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Schedule Page: 328.6 Line No.: 30 Column: m

Intracompany revenues are not reported on the FERC form.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	Not Applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
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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
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	NSTAR ELECTRIC (EAST)							
2	New England Power Co.	OS					-195,733	-195,733
3	Wellesley Municipal Lgt	OS					15,972	15,972
4	Norwood Municipal Light	OS					3,690,862	3,690,862
5	Bell Rock	OS					68,677	68,677
6	Vermont Elec.Trans Co.	OS					251,393	251,393
7	National Grid	OS					7,000,386	7,000,386
8	ISO-NE	OS					390,406,425	390,406,425
9								
10	NSTAR ELECTRIC (WEST)							
11	National Grid	FNS					70,563	70,563
12	Vermont Elec.Trans Co	OS					65,144	65,144
13	National Grid	OS					1,858,688	1,858,688
14	ISO-NE Sch & Dspch	OS					958,586	958,586
15	ISO-NE Reliability	OS					1,008,926	1,008,926
16	Eversource Energy	FNS					3,844,880	3,844,880
	TOTAL						414,526,625	414,526,625

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Deferred Transm. Exp.	OS					-3,797,420	-3,797,420
2	Retail Transm. Deferral	OS					9,279,276	9,279,276
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						414,526,625	414,526,625

Schedule Page: 332 Line No.: 6 Column: g

Hydro Quebec DC Phase 1 Support (Vermont Electric Transmission Co.)	$	251,393

Schedule Page: 332 Line No.: 7 Column: g

Hydro Quebec DC Phase II Support (New England Hydro Transmission Corp)	$	1,674,003
Hydro Quebec Phase II Support Chester SVC (New England Hydro Transmission Corp.)		331,666
Hydro Quebec DC Phase II Support (New England Hydro Transmission Electric Co.)		4,125,175
Hydro Quebec AC Phase II Support (New England Power Co.)		746,320
Hydro Quebec DC Phase I Support (New England Electric Transmission Corp.)		123,222
	$	7,000,386

Schedule Page: 332 Line No.: 12 Column: g

Hydro Quebec DC Phase I Support (Vermont Electric Transmission Co.)

Schedule Page: 332 Line No.: 13 Column: g

Hydro Quebec DC Phase I Support (New England Electric Transmission Corp.)	$ 31,931
Hydro Quebec DC Phase II Support (New England Hydro Transmission Corp.)	444,326
Hydro Quebec DC Phase II Support (New England Hydro Transmission Electric Co.)	1,094,935
Hydro Quebec AC Phase II Support (New England Power Co.)	199,463
Hydro Quebec Phase II Support - Chester SVC (New England Hydro Transmission Corp.)	88,033
Total	$ 1,858,688

Schedule Page: 332 Line No.: 16 Column: g

Associated Company

Schedule Page: 332.1 Line No.: 1 Column: g

NSTAR West

Schedule Page: 332.1 Line No.: 2 Column: g

NSTAR West

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	393,585
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Net Eversource Energy Service Company rate of return	995,598
7	Bank/Debt Fees Other	619,016
8	Trustee Fees and Expensees	1,099,654
9	Employee Compensation and Shareholder Expenses	649,452
10		
11		
12		
13		
14		
15		
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45		
46	TOTAL	3,757,305

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			3,912,051		3,912,051
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	2,832,160				2,832,160
7	Transmission Plant	82,334,485				82,334,485
8	Distribution Plant	171,556,163				171,556,163
9	Regional Transmission and Market Operation					
10	General Plant	11,901,069		818,433		12,719,502
11	Common Plant-Electric					
12	TOTAL	268,623,877		4,730,484		273,354,361

B. Basis for Amortization Charges

Intangible plant amortization relates primarily to computer software which is amortized over 5,10 or 15 years.

General Plant Amortization includes the amortization of leasehold improvements over the life of the lease.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Production						
13	341	17,574			2.43		
14	342						
15	343						
16	344	64,952			3.17		
17	345	4,530			2.99		
18	346						
19	Subtotal Production	87,056					
20							
21	Transmission						
22	352	145,411			2.09		
23	353	1,637,552			2.33		
24	354	42,012			2.00		
25	355	805,598			2.06		
26	356	377,613			2.22		
27	357	145,641			1.95		
28	358	557,422			2.09		
29	359	55,590			1.53		
30	Subtotal Transmission	3,766,839					
31							
32	Distribution						
33	361	114,634			1.46		
34	362	930,452			2.04		
35	364	451,347			3.06		
36	365	878,235			3.04		
37	366	726,010			1.93		
38	367	1,628,613			2.79		
39	368	667,321			3.31		
40	369	402,766			2.79		
41	370	269,921			5.66		
42	371	11,374			7.40		
43	373	39,056			4.35		
44	Subtotal Distribution	6,119,729					
45							
46	General						
47	390	208,192			3.39		
48	391	32,548			7.36		
49	393	3,140			3.98		
50	394	17,255			4.08		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	395	827			4.43		
13	397	96,998			5.30		
14	398	3,589			4.94		
15	Subtotal General	362,549					
16							
17	Intangible						
18	303	60,554			6.43		
19	Subtotal Intangible	60,554					
20							
21	Total	10,396,727					
22							
23							
24							
25							
26							
27							
28							
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Schedule Page: 336 Line No.: 1 Column: d

	EAST	WEST	TOTAL
Account 404 Intangible Plant	2,822,042	1,090,009	3,912,051

Estimated Depreciation accrual on AFUDC equity for the twelve months ended December 2018. This includes 2018 activity through December: West Transmission Intangible Plant $69 & East Transmission Intangible Plant $(31,819).

WEST:
The total amount of Intangible Plant Depreciation Expense in Account 404 includes a transmission-related component of $0.

Schedule Page: 336 Line No.: 7 Column: b

Estimated Depreciation accrual on AFUDC equity for the twelve months ended December 2018. This includes 2018 activity through December: West Transmission Plant $279,080 & East Transmission Plant $71,614.

	EAST	WEST	TOTAL
Account 403 Transmission Plant	59,363,510	22,970,975	82,334,485

EAST:
Information on Formula Rates Page 106 line 23:
Depreciation related to station specific fixed assets.

Information on Formula Rates Page 106 line 30 and 106.2 line 1:
Amount of depreciation as stipulated in contract.

Schedule Page: 336 Line No.: 8 Column: b

	EAST	WEST	TOTAL
Account 403 Distribution	148,064,145	23,492,018	171,556,163

EAST:
Information on Formula Rates Page 106 line 23:
Depreciation related to station specific fixed assets.

Information on Formula Rates Page 106 line 30 and 106.2 line 1:
Amount of depreciation as stipulated in contract.

Schedule Page: 336 Line No.: 10 Column: b

Estimated Depreciation accrual on AFUDC equity for the twelve months ended December 2018. This includes 2018 activity through December: West Transmission General Plant $4,208 & East Transmission General Plant $260,039.

Company	Function	Depreciation Expense
East	General	8,162,024
West Distribution	General	2,468,295
West Transmission	General	1,270,750
Total		**$ 11,901,069**

EAST:

FOOTNOTE DATA

Information on Formula Rates Page 106 line 23:
Depreciation related to station specific fixed assets.

Information on Formula Rates Page 106 line 30 and 106.2 line 1:
Amount of depreciation as stipulated in contract.

Schedule Page: 336 Line No.: 10 Column: d

	EAST	WEST	TOTAL
Account 404 General Plant	608,786	209,647	818,433

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	NSTAR ELECTRIC COMPANY (EAST)				
2	Assessment charged by the Massachusetts				
3	Department of Public Utilities	8,127,806		8,127,806	
4					
5	Proportionate share of expenses of the Federal				
6	Energy Regulatory Commission (FERC)				
7	Assessment Order No. 472	1,950,836		1,950,836	
8					
9	Legal expense-Transmission		61,286	61,286	
10					
11					
12	NSTAR ELECTRIC COMPANY (WEST)				
13	Assessment charged by the Massachusetts				
14	Department of Public Utilities	1,409,567		1,409,567	
15					
16	Proportionate share of expenses of the Federal				
17	Energy Regulatory Commission (FERC)				
18	Assessment Order No. 472	365,598		365,598	
19					
20	Legal expense-Transmission		31,036	31,036	
21					
22	Legal expense-Distribution		1,263	1,263	
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
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40					
41					
42					
43					
44					
45					
46	TOTAL	11,853,807	93,585	11,947,392	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
							2
Electric	928	8,127,806					3
							4
							5
							6
Electric	928	1,950,836					7
							8
Electric	928	61,286					9
							10
							11
							12
							13
Electric	928	1,409,567					14
							15
							16
							17
Electric	928	365,598					18
							19
Electric	928	31,036					20
							21
Electric	928	1,263					22
							23
							24
							25
							26
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		11,947,392					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
					2
					3
					4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	567,940		
4	Transmission	9,988,067		
5	Regional Market			
6	Distribution	43,335,513		
7	Customer Accounts	27,714,309		
8	Customer Service and Informational	11,457,131		
9	Sales			
10	Administrative and General	50,843,834		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	143,906,794		
12	Maintenance			
13	Production			
14	Transmission	4,411,311		
15	Regional Market			
16	Distribution	36,905,420		
17	Administrative and General	3,026		
18	TOTAL Maintenance (Total of lines 13 thru 17)	41,319,757		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	567,940		
21	Transmission (Enter Total of lines 4 and 14)	14,399,378		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	80,240,933		
24	Customer Accounts (Transcribe from line 7)	27,714,309		
25	Customer Service and Informational (Transcribe from line 8)	11,457,131		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	50,846,860		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	185,226,551		185,226,551
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	185,226,551		185,226,551
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	148,754,360		148,754,360
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	148,754,360		148,754,360
72	Plant Removal (By Utility Departments)			
73	Electric Plant	15,452,569		15,452,569
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	15,452,569		15,452,569
77	Other Accounts (Specify, provide details in footnote):	34,520,274		34,520,274
78				
79				
80				
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87				
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93				
94				
95	TOTAL Other Accounts	34,520,274		34,520,274
96	TOTAL SALARIES AND WAGES	383,953,754		383,953,754

Schedule Page: 354 Line No.: 21 Column: b

TOTAL	EAST	WEST
14,399,378	12,357,187	2,042,191

Schedule Page: 354 Line No.: 27 Column: b

TOTAL	EAST	WEST
50,846,860	39,988,877	10,857,983

Schedule Page: 354 Line No.: 28 Column: b

OPERATION:	TOTAL	EAST	WEST
PRODUCTION	567,940	558,223	9,717
TRANSMISSION	9,988,067	8,579,055	1,409,012
REGIONAL MARKET	-	-	-
DISTRIBUTION	43,335,513	37,957,198	5,378,315
CUSTOMER ACCOUNTS	27,714,309	23,819,405	3,894,904
CUSTOMER SERVICE AND INFORMATIONAL	11,457,131	9,161,441	2,295,690
SALES	-	-	-
ADMINISTRATIVE AND GENERAL	50,843,834	39,988,877	10,854,957
TOTAL OPERATION	143,906,794	120,064,199	23,842,595
MAINTENANCE:			
PRODUCTION	-	-	-
TRANSMISSION	4,411,311	3,778,132	633,179
REGIONAL MARKET	-	-	-
DISTRIBUTION	36,905,420	29,821,838	7,083,582
ADMINISTRATIVE AND GENERAL	3,026	-	3,026
TOTAL MAINTENANCE	41,319,757	33,599,970	7,719,787
TOTAL OPERATION AND MAINTENANCE:			
PRODUCTION	567,940	558,223	9,717
TRANSMISSION	14,399,378	12,357,187	2,042,191
REGIONAL MARKET	-	-	-
DISTRIBUTION	80,240,933	67,779,036	12,461,897
CUSTOMER ACCOUNTS	27,714,309	23,819,405	3,894,904
CUSTOMER SERVICE AND INFORMATIONAL	11,457,131	9,161,441	2,295,690
SALES	-	-	-

ADMINISTRATIVE AND GENERAL	50,846,860	39,988,877	10,857,983
TOTAL	185,226,551	153,664,169	31,562,382

Schedule Page: 354 Line No.: 68 Column: b

UTILITY PLANT:	TOTAL	EAST	WEST
ELECTRIC PLANT	148,754,360	127,166,419	21,587,941

Schedule Page: 354 Line No.: 73 Column: b

PLANT REMOVAL:	TOTAL	EAST	WEST
ELECTRIC PLANT	15,452,569	10,785,811	4,666,758

Schedule Page: 354 Line No.: 77 Column: b

OTHER ACCOUNTS:

ACCOUNT	TOTAL	EAST	WEST
123	14,855	14,855	-
143	25,225	25,225	-
146	5,881,755	4,375,883	1,505,872
154	482	482	-
163	(140,701)	(160,883)	20,182
182.3	26,713,916	26,503,493	210,423
183	23,595	-	23,595
184	4,055	3,053	1,002
185	992,846	929,692	63,154
186	413,966	189,599	224,367
228	262,930	223,286	39,644
253	11,874	11,874	-
408	(16,614)	(16,614)	-
417	53,659	5,822	47,837
421	2,122	-	2,122
426	164,829	134,670	30,159
454	111,480	111,480	-
TOTAL	34,520,274	32,351,917	2,168,357

Name of Respondent	This Report Is:	Date of Report *(Mo, Da, Yr)*	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Not Applicable

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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)	(4)	(4)	(4)	(4)
3	Net Sales (Account 447)	(23,245,265)	(34,997,010)	(51,218,281)	(68,370,320)
4	Transmission Rights	(232,071)	(232,071)	(232,071)	(232,071)
5	Ancillary Services	(192)	(188)	(186)	(183)
6	Other Items (list separately)				
7	Forward Capacity Market	(990,965)	(1,985,544)	(3,143,386)	(4,329,151)
8	Other	140,676	103,750	(42,165)	(141,313)
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45					
46	TOTAL	(24,327,821)	(37,111,067)	(54,636,093)	(73,073,042)

FOOTNOTE DATA

Schedule Page: 397 Line No.: 1 Column: e

Prior to 2018, NSTAR Electric (East) reported revenues as positive and expenses as negative on page 397. Starting in 2018, NSTAR Electric (East) will report revenues as negative and expenses as positive to align with NSTAR Electric (West), fka Western Massachusetts Electric Company.

Schedule Page: 397 Line No.: 4 Column: e

Financial Transmission Rights for NSTAR Electric Company West

Schedule Page: 397 Line No.: 5 Column: e

Ancillary Services for NSTAR Electric Company West

Schedule Page: 397 Line No.: 7 Column: e

Forward Capacity Market revenues for NSTAR Electric Company West

Schedule Page: 397 Line No.: 8 Column: e

Other items (Account 447) include various non-day-ahead and real-time energy items billed by ISO-NE, including: demand response, GIS costs, communication expenses, renewable energy certificate revenue, and other miscellaneous prior period reserve and energy adjustments.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch		$/mw	15,215,712		$/mw	7,097,267
2	Reactive Supply and Voltage		$/mw	6,293,800			
3	Regulation and Frequency Response		$/mwh	84		$/mwh	20
4	Energy Imbalance				272,522	$/mwh	52,501,536
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement		$/mwh&$/mw	125		$/mwh&$/mw	372
7	Other		$/mw	2,795,068			
8	Total (Lines 1 thru 7)			24,304,789	272,522		59,599,195

Schedule Page: 398 Line No.: 1 Column: b

Data is not readily available.

Schedule Page: 398 Line No.: 1 Column: d

East	$12,990,162
West	2,225,550
	$15,215,712

Schedule Page: 398 Line No.: 1 Column: e

Data is not readily available.

Schedule Page: 398 Line No.: 1 Column: g

East	$ 7,095,441
West	1,826
	$ 7,097,267

Schedule Page: 398 Line No.: 2 Column: b

Data is not readily available.

Schedule Page: 398 Line No.: 2 Column: d

East	$ 5,695,723
West	598,077
	$ 6,293,800

Schedule Page: 398 Line No.: 3 Column: b

Data is not readily available.

Schedule Page: 398 Line No.: 3 Column: d

East	-
West	84
	84

Schedule Page: 398 Line No.: 3 Column: e

Data is not readily available.

Schedule Page: 398 Line No.: 3 Column: g

East	-
West	20
	20

Schedule Page: 398 Line No.: 4 Column: e

East	-
West	272,522
	272,522

Schedule Page: 398 Line No.: 4 Column: g

East	$ 43,504,238
West	8,997,298
	$ 52,501,536

Schedule Page: 398 Line No.: 5 Column: d

Allocation of Operating Reserves is not readily available.

Schedule Page: 398 Line No.: 5 Column: g

Allocation of Operating Reserves is not readily available.

Schedule Page: 398 Line No.: 6 Column: b

Data is not readily available.

Schedule Page: 398 Line No.: 6 Column: d

Allocation of Operating Reserves is not readily available.

East	-
West	125
	125

Schedule Page: 398 Line No.: 6 Column: e

Data is not readily available.

Schedule Page: 398 Line No.: 6 Column: g

Allocation of Operating Reserves is not readily available.

East	-
West	372
	372

Schedule Page: 398 Line No.: 7 Column: b

Data is not readily available.

Schedule Page: 398 Line No.: 7 Column: d

East	$ 2,384,218
West	410,850
	$ 2,795,068

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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: NSTAR ELECTRIC COMPANY (EAST)

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	4,309	5	18	3,467	663	93	179		
2	February	3,732	2	18	3,007	546	93	179		
3	March	3,631	7	18	2,852	526	93	253		
4	Total for Quarter 1				9,326	1,735	279	611		
5	April	3,337	2	11	2,674	484	93	179		
6	May	3,801	29	18	2,941	562	93	298		
7	June	4,603	18	18	3,643	662	93	298		
8	Total for Quarter 2				9,258	1,708	279	775		
9	July	5,358	3	17	4,391	788	93	179		
10	August	5,621	29	17	4,633	836	93	152		
11	September	5,370	6	16	4,420	786	93	164		
12	Total for Quarter 3				13,444	2,410	279	495		
13	October	3,830	10	18	3,096	555	93	179		
14	November	3,710	15	18	2,914	538	93	258		
15	December	3,914	18	18	3,045	571	93	298		
16	Total for Quarter 4				9,055	1,664	279	735		
17	Total Year to Date/Year				41,083	7,517	1,116	2,616		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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: NSTAR ELECTRIC COMPANY (WEST)

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	993	5	18	617	329		47		
2	February	883	7	18	546	290		47		
3	March	793	7	18	489	257		47		
4	Total for Quarter 1				1,652	876		141		
5	April	758	3	20	466	242		50		
6	May	855	29	18	509	266		80		
7	June	1,055	18	17	643	334		78		
8	Total for Quarter 2				1,618	842		208		
9	July	1,111	2	17	705	359		47		
10	August	1,191	29	17	715	366		110		
11	September	1,085	6	15	706	363		16		
12	Total for Quarter 3				2,126	1,088		173		
13	October	801	10	19	513	260		28		
14	November	869	15	18	517	274		78		
15	December	915	18	18	544	293		78		
16	Total for Quarter 4				1,574	827		184		
17	Total Year to Date/Year				6,970	3,633		706		

FOOTNOTE DATA

Schedule Page: 400 Line No.: 17 Column: b

Information on Formula Rates Page 106 lines 10 & 13:
Ratio of fixed load per contract divided by station peak load per company records.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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: Not Applicable

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									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	23,999,384
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	276
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,262,017
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	27,440
7	Other	8,824	27	Total Energy Losses	1,349,772
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	26,638,889
9	Net Generation (Enter Total of lines 3 through 8)	8,824			
10	Purchases	26,630,065			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	28,794,602			
17	Delivered	28,794,602			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	26,638,889			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: NSTAR ELECTRIC COMPANY

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	2,445,579	141,725	3,466	5	1800
30	February	2,011,028	133,535	3,003	2	1800
31	March	2,168,569	160,171	2,852	7	1800
32	April	1,983,241	134,566	2,672	2	1100
33	May	1,960,204	54,607	2,942	29	1800
34	June	2,193,155	152,685	3,643	18	1800
35	July	2,710,676	98,274	4,392	3	1700
36	August	2,759,534	81,834	4,644	29	1700
37	September	2,198,665	89,242	4,420	6	1600
38	October	2,028,955	96,413	3,096	10	1800
39	November	2,059,933	96,149	2,914	15	1800
40	December	2,119,350	22,816	3,045	18	1800
41	TOTAL	26,638,889	1,262,017			

Schedule Page: 401 Line No.: 10 Column: b

Purchases include competitive supplier loads.

Schedule Page: 401 Line No.: 29 Column: b

The Total Monthly Energy (MWH) and Monthly Non-Requirements Sales for Resales (columns a and b) are the combined East and West totals. Please see the footnote for line 29, column d regarding the separation of East and West monthly peaks.

Schedule Page: 401 Line No.: 29 Column: d

NSTAR Electric maintains 2 power systems that are not physically integrated. Per instruction 1, the required information on page 401b is furnished separately for each non-integrated system's monthly peaks. NSTAR Electric (East) data is displayed on the main page and NSTAR Electric (West) data is displayed in the footnote.

NSTAR ELECTRIC COMPANY (WEST)

		Monthly Peak	
Month	Megawatts	Day of Month	Hour
Jan	620	5	1800
Feb	549	7	1800
Mar	496	7	1900
Apr	469	16	1400
May	516	29	1900
Jun	645	18	1700
Jul	706	2	1800
Aug	729	29	1800
Sep	707	6	1500
Oct	516	10	2000
Nov	518	15	1800
Dec	548	18	1800

EAST:

Information on Formula Rates Page 106 line 27:

Ratio of 12-month average transmission load divided by reference year 1993 transmission load per contract

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		
38	Quantity (Units) of Fuel Burned	0 0 0	0 0 0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0 0 0	0 0 0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000 0.000 0.000	0.000 0.000 0.000
41	Average Cost of Fuel per Unit Burned	0.000 0.000 0.000	0.000 0.000 0.000
42	Average Cost of Fuel Burned per Million BTU	0.000 0.000 0.000	0.000 0.000 0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000 0.000 0.000	0.000 0.000 0.000
44	Average BTU per KWh Net Generation	0.000 0.000 0.000	0.000 0.000 0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
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			10
			11
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Silver Lake, Pittsfield MA	2010				9,070,493
2	Goodwin Street (Indian Orchard), Springfield MA	2011				11,550,512
3	Cottage Street, Spingfield MA	2014				14,012,752
4	Millers Falls Rd, Montague, MA	2018				10,202,357
5	Chapin Street, Ludlow	2018				5,377,495
6	Feeding Hills Rd, Southwick MA	2018				14,216,525
7	Amherst Rd, Sunderland MA	2018				3,050,041
8	Denslow Rd, Longmeadow MA	2018				1,602,803
9	Water Street, Lee MA	2018				5,723,305
10	Partridge Rd, Pittsfield MA	2018				4,015,705
11	Cadwell Dr, East Springfield MA	2018				7,161,143
12	Plain Rd, Hatfield MA	2018				10,666,517
13	Duchaine Blvd, Bedford MA	2018				5,041,608
14	Summer Street, Plymouth MA	2018				5,834,933
15	Log Plain Rd, Greenfield MA	2018				6,337,947
16	New Windsor Rd, Hinsdale MA	2018				6,303,001
17	Valley Rd, Southhampton MA	2018				6,745,815
18	Roosevelt Ave, Springfield MA	2018				10,056,561
19	Windsor Rd, Savoy MA	2018				6,533,501
20	Tobey Rd, Wareham MA	2018				8,988,091
21	Station Drive, Westwood MA	2018				3,096,131
22						
23						
24						
25						
26						
27						
28						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
						2
						3
						4
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						14
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						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	OVERHEAD							
2	West Medway Station #446	Eversource/NGRID (Medway)	345.00	345.00	Steel	0.14		1
3	West Medway Station #446	West Walpole Station #447	345.00	345.00	Steel	9.62		1
4	West Walpole Station #447	Eversource/NGRID (Walpole)	345.00	345.00	Steel		0.65	1
5	Stoughton Station #330	West Walpole Station #447	345.00	345.00	Steel	9.04		1
6	Holbrook Station #478	Stoughton Station #330	345.00	345.00	Steel	5.62		1
7	West Medway Station #446	Eversource/NGRID (Walpole)	345.00	345.00	Steel		8.94	1
8	Whitman Station #451	Holbrook Station #478	345.00	345.00	Steel	7.20		1
9	Woburn Station #211	Eversource/NGRID(Billerica)	345.00	345.00	Wood/Steel	6.21		1
10	Pilgrim Station #650	Plymouth (M Standish Tap)	345.00	345.00	Steel	7.31		1
11	Pilgrim Station #650	Plymouth (M Standish Tap)	345.00	345.00	Steel		7.30	1
12	Miles Standish Tap	Whitman Station (Nat'l Grd)	345.00	345.00	Steel	26.00		1
13	West Medway Station #446	West Walpole Station #447	345.00	345.00	Wood/Steel	9.60		1
14	West Medway Station #446	Eversource/NGRID (Milford)	345.00	345.00	Wood/Steel	1.82		1
15	Lexington Station #320	Woburn Station #211	345.00	345.00	Wood/Steel	8.24		1
16	West Medway Station #446	Eversource/NGRID (Milford)	345.00	345.00	Steel	1.87		1
17	Bellingham Tap 336	NEA	345.00	345.00	Wood	0.03		1
18	Bellingham Tap 336	Blackstone Station #309	345.00	345.00	Wood/Steel	2.67		1
19	Blackstone Station #309	(Mass/R.I. Line)	345.00	345.00	Wood/Steel	10.72		1
20	Canal Station #980	Cape Cod Canal (Str 24)	345.00	345.00	Wood/Steel	12.68		1
21	Cape Cod Canal (Str 24)	Cape Cod Canal (Str 27)	345.00	345.00	Steel	0.49		1
22	Cape Cod Canal (Str 27)	Carver Station #726	345.00	345.00	Wood/Steel	7.26		1
23	Carver Station #726	Myles Standish Tap	345.00	345.00	Steel	7.27		1
24	Myles Standish Tap	Cape Cod Canal (Str 4)	345.00	345.00	Steel	9.99		1
25	Cape Cod Canal (Str 4)	Cape Cod Canal (Str 1)	345.00	345.00	Steel	0.60		1
26	Cape Cod Canal (Str 1)	West Barnstable #921	345.00	345.00	Steel	12.71		1
27	Carver Station #726	Eversource/NGRID(Bridgewat	345.00	345.00	Wood/Steel	9.67		1
28	Canal Station #980	Cape Cod Canal (Str 17B)	345.00	345.00	Steel	2.65		1
29	Cape Cod Canal (Str 17B)	Cape Cod Canal (Str 20)	345.00	345.00	Steel	0.61		2
30	Myles Standish Tap	Carver Station #726	345.00	345.00	Steel	7.29		1
31	Eversource/NGRID(Bridgewat	Carver Station #726	345.00	345.00	Steel	9.48		1
32	West Medway Station #446	Bellingham Tap 336	345.00	345.00	Wood/Steel	5.22		1
33	Cape Code Canal (Str 20)	Miles Standish Tap	345.00	345.00	Steel	9.86		1
34	Ludlow S/S	Carpenter Hill S/S	345.00	345.00	SCHF	2.99		1
35	Northfield Mountain Station	Berkshire S/S	345.00	345.00	SCHF	36.91		1
36					TOTAL	1,272.51	226.98	288

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Northfield Mountain Station	Ludlow S/S	345.00	345.00	SCHF	29.30		1
2	Northfield Mountain Station	Vermont Yankee Station	345.00	345.00	SCHF	9.30		1
3	Berkshire S/S	Alps S/S	345.00	345.00	SCHF	14.60		1
4	Ludlow S/S	Barbour Hill S/S	345.00	345.00	SCHF	11.72		1
5	Agawam S/S	Ludlow S/S	345.00	345.00	SCSP	3.20		1
6					DCSP	14.34		
7	Agawam S/S	North Bloomfield 2A	345.00	345.00	SCSP	0.73		1
8					DCSP	5.29		
9	West Medway Station #446	Leland Street Station #240	230.00	230.00	Steel	10.16		1
10	West Medway Station #446	Leland Street Station #240	230.00	230.00	Wood	0.54		
11	West Medway Station #446	Sudbury Station #342	230.00	230.00	Steel		10.16	1
12	West Medway Station #446	Sudbury Station #342	230.00	230.00	Wood/Steel	7.50		
13	Sudbury Station #342	Waltham Station #282	230.00	230.00	Steel		7.20	1
14	Various Locations - East	Various Locations	115.00	115.00	Overhead	415.12	80.47	112
15	Various Locations - West		115.00	115.00	Overhead	236.41	112.26	55
16	Various Locations - West		69.00	69.00	Overhead	5.50		1
17	UNDERGROUND							
18	No. Cambridge Station #509	Woburn Station #211	345.00	345.00	Underground	12.02		2
19	Everett Station #250	No. Cambridge Station #509	345.00	345.00	Underground	9.92		2
20	Everett Station #250	Saugus Nat'l Grid Sta. #90	345.00	345.00	Underground	12.58		1
21	Everett Station #250	Boston Station #514	345.00	345.00	Underground	8.40		2
22	Stoughton Station #330	Hyde Park St. #496 C 3164	345.00	345.00	Underground	11.19		1
23	Stoughton Station #330	K St. Station #385, C 3162	345.00	345.00	Underground	17.40		1
24	Stoughton Station #330	K St. Station #385, C 3163	345.00	345.00	Underground	17.40		1
25	Various Locations - East	Various Locations	115.00	115.00	Underground	167.97		58
26	Various Locations - West		115.00	115.00	Underground	10.15		8
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,272.51	226.98	288

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10	Oper. & Maint.Transm. Line							
11								
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27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,272.51	226.98	288

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
2-900 AL		871	871					2
2500 ACSR		1,777,751	1,777,751					3
2500 ACSR	97,030	14,255,004	14,352,034					4
2-1590 ACSR		9,578	9,578					5
2-1590 ACSR		4,121,756	4,121,756					6
2-1703 ACAR		1,452,209	1,452,209					7
2-1590 ACSR		757,354	757,354					8
2-954 ACSR		3,278,657	3,278,657					9
2-1703 ACAR	187,112	4,558,594	4,745,706					10
2-1703 ACAR	144,712	7,026,074	7,170,786					11
2-1590 ACSR								12
2-954 ACSR		5,547,183	5,547,183					13
2-900 AL		2,784,110	2,784,110					14
2-1113 ACSR		7,069,463	7,069,463					15
2-1113 ACSR		193,004	193,004					16
2-1024.5 ACAR								17
2-900 ACSS	320,652	15,463,479	15,784,131					18
2-900 ACSS		16,767,487	16,767,487					19
2335 ACAR	210,177	22,792,600	23,002,777					20
2335 ACAR								21
2335 ACAR								22
2-954 ACSS		17,596,844	17,596,844					23
2-954 ACSS								24
2338 ACAR								25
2-1703 ACAR								26
2335 ACAR								27
2-1703 ACAR								28
2338 ACAR								29
2-1703 ACAR								30
2-1703 ACAR		963,034	963,034					31
2-900 ACSS								32
2-1703 ACAR								33
2156 ACSR	190,492	5,188,732	5,379,224					34
2-954 ACSR	1,741,464	35,413,260	37,154,724					35
	34,892,305	2,017,737,865	2,052,630,170	7,100,331	10,336,780	91,574	17,528,685	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2-954 ACSR	1,983,154	56,100,158	58,083,312					1
2-954 ACSR	213,175	18,000,544	18,213,719					2
2156 ACSR	574,004	11,275,212	11,849,216					3
2156 ACSR	928,313	12,194,478	13,122,791					4
2-1590 ACSS	12,706,780	79,945,860	92,652,640					5
								6
2-1590 ACSS	5,317,429	27,181,967	32,499,396					7
								8
1113 ACSR		539,270	539,270					9
1113 ACSR								10
1113 ACSR								11
1113 ACSR								12
1113 ACSR		2,002,590	2,002,590					13
Various	2,615,514	482,008,087	484,623,601					14
	7,139,595	417,129,449	424,269,044					15
	165,678	7,428,692	7,594,370					16
								17
CU-2-2500		6,186,283	6,186,283					18
CU-2500	77,817	5,155,676	5,233,493					19
CU-2-2500		5,874,583	5,874,583					20
CU-2500		36,485,845	36,485,845					21
2500CU		41,929,542	41,929,542					22
2500CU		67,787,186	67,787,186					23
2500CU		82,747,899	82,747,899					24
Various	263,540	475,768,992	476,032,532					25
	15,667	14,978,508	14,994,175					26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	34,892,305	2,017,737,865	2,052,630,170	7,100,331	10,336,780	91,574	17,528,685	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
								2
								3
								4
								5
								6
								7
								8
								9
				7,100,331	10,336,780	91,574	17,528,685	10
								11
								12
								13
								14
								15
								16
								17
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								32
								33
								34
								35
	34,892,305	2,017,737,865	2,052,630,170	7,100,331	10,336,780	91,574	17,528,685	36

FOOTNOTE DATA

Schedule Page: 422 Line No.: 12 Column: l

Cost included in line 11.

Schedule Page: 422 Line No.: 17 Column: l

Cost included in line 18.

Schedule Page: 422 Line No.: 21 Column: l

Cost included in line 20.

Schedule Page: 422 Line No.: 22 Column: l

Cost included in line 20.

Schedule Page: 422 Line No.: 24 Column: l

Cost included in line 23.

Schedule Page: 422 Line No.: 25 Column: l

Cost included in line 23.

Schedule Page: 422 Line No.: 26 Column: l

Cost included in line 23.

Schedule Page: 422 Line No.: 27 Column: l

Cost included in line 4.

Schedule Page: 422 Line No.: 28 Column: l

Cost included in line 11.

Schedule Page: 422 Line No.: 29 Column: l

Cost included in line 11.

Schedule Page: 422 Line No.: 30 Column: l

Cost included in line 10.

Schedule Page: 422 Line No.: 32 Column: l

Cost included in line 18.

Schedule Page: 422 Line No.: 33 Column: l

Cost included in line 11.

Schedule Page: 422.1 Line No.: 10 Column: l

Cost included in line 9.

Schedule Page: 422.1 Line No.: 11 Column: l

Cost included in line 13.

Schedule Page: 422.1 Line No.: 12 Column: l

Cost included in line 13.

Schedule Page: 422.2 Line No.: 10 Column: m

East	$6,362,780
West	737,551
	$7,100,331

Schedule Page: 422.2 Line No.: 10 Column: n

East	$ 4,648,115
West	5,688,665
	$10,336,780

Schedule Page: 422.2 Line No.: 10 Column: o

East	$47,732
West	43,842
	$91,574

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.

2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From	To		Type	Average Number per Miles	Present	Ultimate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	NONE						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
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36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
									2
									3
									4
									5
									6
									7
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	EAST				
2	Sub #2 Boston	Dist.-Unatt.	115.00	13.80	
3	Sub #4 S. Boston	Dist.-Unatt.	115.00	13.80	
4	Sub #12 Boston	Dist.-Unatt.	115.00	13.80	
5	Sub #13 Roslindale	Dist.-Unatt.	13.80	4.16	
6	Sub #16 Somerville	Dist.-Unatt.	13.80	4.16	
7	Sub #17 Newton Center	Dist.-Unatt.	24.00	13.80	
8	Sub #17 Newton Center	Dist.-Unatt.	13.80	4.16	
9	Sub #20 Dedham	Dist.-Unatt.	24.00	13.80	
10	Sub #20 Dedham	Dist.-Unatt.	13.80	4.16	
11	Sub #23 Natick	Dist.-Unatt.	13.80	4.16	
12	Sub #24 Framingham	Dist.-Unatt.	13.80	4.16	
13	Sub #26 Walpole	Dist.-Unatt.	13.80	4.16	
14	Sub #30 Boston	Dist.-Unatt.	13.80	4.16	
15	Sub #33 Waltham	Dist.-Unatt.	13.80	4.16	
16	Sub #34 Lexington	Dist.-Unatt.	13.80	4.16	
17	Sub #36 Allston	Dist.-Unatt.	13.80	4.16	
18	Sub #43 Dorchester	Dist.-Unatt.	13.80	4.16	
19	Sub #49 Boston	Dist.-Unatt.	13.80	4.16	
20	Sub #52 Roxbury	Dist.-Unatt.	13.80	4.16	
21	Sub #53 Boston	Dist.-Unatt.	115.00	13.80	
22	Sub #59 Arlington	Dist.-Unatt.	13.80	4.16	
23	Sub #60 Hyde Park	Dist.-Unatt.	13.80	4.16	
24	Sub #65 West Medway	Dist.-Unatt.	115.00	13.80	
25	Sub #67 Dorchester	Dist.-Unatt.	13.80	4.16	
26	Sub #71 Boston	Dist.-Unatt.	115.00	13.80	
27	Sub #99 S. Boston	Dist.-Unatt.	115.00	13.80	
28	Sub #106 S. Boston	Dist.-Unatt.	115.00	13.80	
29	Sub #110 W. Roxbury	Dist.-Unatt.	115.00	24.00	
30	Sub #110 W. Roxbury	Dist.-Unatt.	115.00	115.00	
31	Sub #124 Watertown	Dist.-Unatt.	13.80	4.16	
32	Sub #126 Hopkinton	Dist.-Unatt.	115.00	13.80	
33	Sub #130 Holliston	Dist.-Unatt.	115.00	13.80	
34	Sub #139 S. Boston	Dist.-Unatt.	13.80	4.16	
35	Sub #143 Roxbury	Dist.-Unatt.	13.80	4.16	
36	Sub #146 Walpole	Dist.-Unatt.	115.00	13.80	
37	Sub #148 Needham	Dist.-Unatt.	13.80	4.16	
38	Sub #148 Needham	Dist.-Unatt.	115.00	13.80	
39	Sub #211 Winchester/Woburn	Dist.-Unatt.	115.00	13.80	
40	Sub #211 Winchester/Woburn	Dist.-Unatt.	13.80	4.16	

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Sub #240 Framingham	Dist.-Unatt.	115.00	13.80	
2	Sub #250 Charlestown/Everett	Dist.-Unatt.	115.00	13.80	
3	Sub #250 Charlestown/Everett	Dist.-Unatt.	24.00	13.80	
4	Sub #274 Sherborn	Dist.-Unatt.	115.00	13.80	
5	Sub #277 Newtonville	Dist.-Unatt.	13.80	4.16	
6	Sub #278 Saxonville	Dist.-Unatt.	115.00	13.80	
7	Sub #282 Waltham	Dist.-Unatt.	115.00	13.80	
8	Sub #284 Jamaica Plain	Dist.-Unatt.	13.80	4.16	
9	Sub #285 E. Watertown	Dist.-Unatt.	13.80	4.16	
10	Sub #292 Newton	Dist.-Unatt.	115.00	13.80	
11	Sub #292 Newton	Dist.-Unatt.	13.80	4.16	
12	Sub #293 S. Boston	Dist.-Unatt.	13.80	4.16	
13	Sub #301 Stoneham	Dist.-Unatt.	13.80	4.16	
14	Sub #311 Mattapan	Dist.-Unatt.	13.80	4.16	
15	Sub #315 Brighton	Dist.-Unatt.	115.00	13.80	
16	Sub #316 W. Newton	Dist.-Unatt.	13.80	4.16	
17	Sub #318 Boston	Dist.-Unatt.	13.80	4.16	
18	Sub #320 Lexington	Dist.-Unatt.	115.00	13.80	
19	Sub #321 Dorchester	Dist.-Unatt.	13.80	4.16	
20	Sub #322 Bedford	Dist.-Unatt.	13.80	4.16	
21	Sub #323 Boston	Dist.-Unatt.	13.80	4.16	
22	Sub #325 Woburn	Dist.-Unatt.	13.80	4.16	
23	Sub #329 Brighton	Dist.-Unatt.	115.00	24.00	13.80
24	Sub #329 Brighton	Dist.-Unatt.	115.00	13.80	
25	Sub #340 Boston	Dist.-Unatt.	13.80	4.16	
26	Sub #342 Sudbury	Dist.-Unatt.	115.00	13.80	
27	Sub #344 Hyde Park	Dist.-Unatt.	13.80	4.16	
28	Sub #350 Boston	Dist.-Unatt.	115.00	13.80	
29	Sub #351 E. Lexington	Dist.-Unatt.	13.80	4.16	
30	Sub #355 Maynard	Dist.-Unatt.	13.80	4.16	
31	Sub #360 Sudbury	Dist.-Unatt.	13.80	4.16	
32	Sub #362 Milton	Dist.-Unatt.	13.80	4.16	
33	Sub #369 Newton	Dist.-Unatt.	13.80	4.16	
34	Sub #374 W. Roxbury	Dist.-Unatt.	24.00	4.16	
35	Sub #375 N. Woburn	Dist.-Unatt.	115.00	13.80	
36	Sub #385 S. Boston	Dist.-Unatt.	115.00	13.80	
37	Sub #391 Burlington	Dist.-Unatt.	115.00	13.80	
38	Sub #396 Roxbury	Dist.-Unatt.	24.00	4.16	
39	Sub #402 Somerville	Dist.-Unatt.	115.00	13.80	
40	Sub #416 Maynard	Dist.-Unatt.	115.00	13.80	

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Sub #430 S. Boston	Dist.-Unatt.	13.80	4.16	
2	Sub #433 Framingham	Dist.-Unatt.	115.00	13.80	
3	Sub #441 Roslindale	Dist.-Unatt.	13.80	4.16	
4	Sub #443 W. Roxbury	Dist.-Unatt.	24.00	4.16	
5	Sub #445 Chelsea	Dist.-Unatt.	24.00	13.80	
6	Sub #450 Waltham	Dist.-Unatt.	115.00	13.80	
7	Sub #454 Dorchester	Dist.-Unatt.	13.80	4.16	
8	Sub #455 Framingham	Dist.-Unatt.	115.00	13.80	
9	Sub #456 Dover	Dist.-Unatt.	115.00	13.80	
10	Sub #467 Watertown	Dist.-Unatt.	115.00	13.80	
11	Sub #468 W. Roxbury	Dist.-Unatt.	24.00	4.16	
12	Sub #469 W. Somerville	Dist.-Unatt.	13.80	4.16	
13	Sub #470 Canton	Dist.-Unatt.	115.00	13.80	
14	Sub #483 Dorchester	Dist.-Unatt.	115.00	13.80	
15	Sub #483 Dorchester	Dist.-Unatt.	13.80	4.16	
16	Sub #488 Chelsea	Dist.-Unatt.	115.00	13.80	
17	Sub #492 Boston	Dist.-Unatt.	115.00	13.80	
18	Sub #496 Hyde Park	Dist.-Unatt.	115.00	13.80	
19	Sub #506 Brookline	Dist.-Unatt.	13.80	4.16	
20	Sub #514 Boston	Dist.-Unatt.	115.00	13.80	
21	Sub #516 W. Roxbury	Dist.-Unatt.	24.00	4.16	
22	Sub #533 Lexington	Dist.-Unatt.	115.00	13.80	
23	Sub #611 New Bedford	Dist.-Unatt.	115.00	13.20	
24	Sub #612 Acushnet	Dist.-Unatt.	115.00	13.20	
25	Sub #624 Acushnet	Dist.-Unatt.	115.00	13.20	
26	Sub #636 New Bedford	Dist.-Unatt.	115.00	13.20	
27	Sub #646 Mattapoisett	Dist.-Unatt.	115.00	13.20	
28	Sub #651 Dartmouth	Dist.-Unatt.	115.00	13.20	
29	Sub #654 Fairhaven	Dist.-Unatt.	115.00	13.20	
30	Sub #657 Dartmouth	Dist.-Unatt.	115.00	13.20	
31	Sub #661 Fall River	Dist.-Unatt.	115.00	34.50	
32	Sub #713 Wareham	Dist.-Unatt.	115.00	23.00	
33	Sub #714 Wareham	Dist.-Unatt.	115.00	23.00	
34	Sub #715 Plymouth	Dist.-Unatt.	115.00	23.00	
35	Sub #721 Plymouth	Dist.-Unatt.	115.00	23.00	
36	Sub #727 Plympton	Dist.-Unatt.	115.00	23.00	
37	Sub #735 Kingston	Dist.-Unatt.	115.00	23.00	
38	Sub #737 Plymouth	Dist.-Unatt.	115.00	23.00	
39	Sub #738 Duxbury	Dist.-Unatt.	115.00	23.00	
40	Sub #739 Marshfield	Dist.-Unatt.	115.00	23.00	

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Sub #745 Rochester	Dist.-Unatt.	115.00	13.20	
2	Sub #817 Cambridge	Dist.-Unatt.	13.80	4.16	
3	Sub #824 Cambridge	Dist.-Unatt.	13.80	4.16	
4	Sub #827 Cambridge	Dist.-Unatt.	13.80	4.16	
5	Sub #828 W. Cambridge	Dist.-Unatt.	117.50	14.40	
6	Sub #831 Cambridge	Dist.-Unatt.	117.50	14.40	
7	Sub #875 E. Cambridge	Dist.-Unatt.	117.50	14.40	
8	Sub #915 Bourne	Dist.-Unatt.	115.00	23.00	
9	Sub #916 Sandwich	Dist.-Unatt.	115.00	23.00	
10	Sub #920 Barnstable	Dist.-Unatt.	115.00	23.00	
11	Sub #933 Falmouth	Dist.-Unatt.	115.00	23.00	
12	Sub #936 Falmouth	Dist.-Unatt.	115.00	23.00	
13	Sub #946 Mashpee	Dist.-Unatt.	115.00	23.00	
14	Sub #961 Hyannis	Dist.-Unatt.	115.00	23.00	
15	Sub #968 Harwich	Dist.-Unatt.	115.00	23.00	
16	Sub #976 Wellfleet	Dist.-Unatt.	115.00	23.00	
17	Sub #975 Orleans	Dist.-Unatt.	115.00	23.00	
18	Primary Network Units (18)	Dist.-Unatt.			
19	Mobile Transformers	Dist.-Unatt.	115.00	13.80	
20	Mobile Transformers	Dist.-Unatt.	115.00	23.00	
21	Minor Substations	Dist.-Unatt.			
22	Sub #150 N. Weymouth	Trans.-Unatt.	115.00	115.00	
23	Sub #211 Winchester/Woburn	Trans.-Unatt.	345.00	115.00	
24	Sub #240 Framingham	Trans.-Unatt.	230.00	115.00	
25	Sub #250 Charlestown/Everett	Trans.-Unatt.	345.00	115.00	
26	Sub #282 Waltham	Trans.-Unatt.	230.00	115.00	
27	Sub #320 Lexington	Trans.-Unatt.	345.00	115.00	
28	Sub #330 Stoughton	Trans.-Unatt.	345.00	345.00	
29	Sub #342 Sudbury	Trans.-Unatt.	230.00	115.00	
30	Sub #385 S. Boston	Trans.-Unatt.	345.00	115.00	
31	Sub #446 W. Medway	Trans.-Unatt.	345.00	230.00	
32	Sub #447 W. Walpole	Trans.-Unatt.	345.00	115.00	
33	Sub #478 Holbrook	Trans.-Unatt.	345.00	115.00	
34	Sub #479 Milford	Trans.-Unatt.	115.00	115.00	
35	Sub #496 Hyde Park	Trans.-Unatt.	345.00	115.00	
36	Sub #509 N. Cambridge	Trans.-Unatt.	345.00	115.00	
37	Sub #514 Boston	Trans.-Unatt.	345.00	115.00	
38	Sub #726 Carver	Trans.-Unatt.	345.00	115.00	22.00
39	Sub #921 Barnstable	Trans.-Unatt.	345.00	115.00	
40	Sub #924 Falmouth tap	Trans.-Unatt.	115.00		

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Sub #958 Barnstable	Trans.-Unatt.	115.00	115.00	
2	Sub #958 Barnstable	Trans.-Unatt.	115.00	115.00	
3	Sub #980 Sandwich	Trans.-Unatt.	345.00	115.00	22.00
4					
5	WEST				
6	Agawam 16C, Agawam	Dist.-Unatt.-With TL	345.00	115.00	
7	Agawam 16C, Agawam	Dist.-Unatt.-With TL	115.00	13.80	
8	Amherst 17K, Amherst	Dist.-Unatt.-With TL	115.00	13.80	
9	Ashfield 38A, Ashfield	Dist.-Unatt.-With TL	115.00	23.00	
10	Berkshire 18C, Hinsdale	Dist.-Unatt.-With TL	345.00	115.00	
11	Berkshire 18C, Hinsdale	Dist.-Unatt.-With TL	115.00	23.00	
12	Blandford 19J, Blandford	Dist.-Unatt.-With TL	115.00	23.00	
13	Breckwood 20A, Springfield	Dist.-Unatt.-With TL	115.00	13.80	
14	Clinton 21S, Springfield	Dist.-Unatt.-With TL	115.00	13.80	
15	Cumberland 22B, Greenfield	Dist.-Unatt.-With TL	115.00	13.80	
16	Doreen 19A, Pittsfield	Dist.-Unatt.-With TL	115.00	23.00	
17	East Springfield 5J, Springfield	Dist.-Unatt.-With TL	115.00	13.80	
18	Franconia 22H, Longmeadow	Dist.-Unatt.-With TL	115.00	13.80	
19	French King 21B, Erving	Dist.-Unatt.-With TL	115.00	13.80	
20	Gunn 15A, Easthampton	Dist.-Unatt.-With TL	115.00	23.00	
21	Ludlow 19S, Ludlow	Dist.-Unatt.-With TL	345.00	115.00	
22	Ludlow 19S, Ludlow	Dist.-Unatt.-With TL	115.00	13.80	
23	Midway 19B, Easthampton	Dist.-Unatt.-With TL	115.00	13.80	
24	Midway 19B, Easthampton	Dist.-Unatt.-With TL	13.80	13.80	
25	Montague 21C, Montague	Dist.-Unatt.-With TL	115.00	13.80	
26	Orchard 27A, Springfield	Dist.-Unatt.-With TL	115.00	13.80	
27	Oswald 30B, Pittsfield	Dist.-Unatt.-With TL	115.00	23.00	
28	Partridge 15E, Pittsfield	Dist.-Unatt.-With TL	115.00	23.00	
29	Piper 21N, West Springfield	Dist.-Unatt.-With TL	115.00	13.80	
30	Plainfield 18K, Plainfield	Dist.-Unatt.-With TL	115.00	23.00	
31	Pleasant 16B, Lee	Dist.-Unatt.-With TL	115.00	23.00	
32	Podick 18G, Amherst	Dist.-Unatt.-With TL	115.00	13.80	
33	Shelburne 29R, Shelburne	Dist.-Unatt.-With TL	69.00	13.80	
34	Silver 30A, Agawam	Dist.-Unatt.-With TL	115.00	13.80	
35	Southwick 29A, Southwick	Dist.-Unatt.-With TL	115.00	23.00	
36	West Springfield 8C,W. Springfield	Dist.-Unatt.-With TL	115.00	13.80	
37	Woodland 17G, Lee	Dist.-Unatt.-With TL	115.00	23.00	
38	Converse, 7J Springfield	Dist.-Unatt.-No TL	13.80	4.16	
39	Dalton 29M, Dalton	Dist.-Unatt.-No TL	23.00	8.32	
40	Silver Lake 5C, Pittsfield	Dist.-Unatt.-No TL	23.00	4.16	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Silver Lake 5C, Pittsfield	Dist.-Unatt.-No TL			
2	Wilbraham Avenue 6N, Springfield	Dist.-Unatt.-No TL	13.80	4.16	
3	Dell Street 29H, Montague	Dist.-Unatt.-No TL	13.80	4.80	
4	Greenfield 28W, Greenfield	Dist.-Unatt.-No TL	13.80	4.80	
5	North Street 23G, Ludlow	Dist.-Unatt.-No TL	13.80	11.50	
6	Pomeroy, Pittsfield				
7	Ravenwood 32N, Ludlow	Dist.-Unatt.-No TL	13.80	4.16	
8	Ravenwood 32N, Ludlow	Dist.-Unatt.-No TL	13.80	0.48	
9	Seymour, Pittsfield				
10	Worthington 4G, Pittsfield	Dist.-Unatt.-No TL	23.00	4.16	
11	Cadwell 50F, Springfield	Trans.-Unatt.	345.00		
12	Erving 38F, Erving	Trans.-Unatt.	115.00		
13	Fairmont 16H, Chicopee	Trans.-Unatt.	115.00		
14	Mount Tom 22C, Holyoke	Trans.-Unatt.	115.00		
15	Northfield Mtn 16R, Northfield	Trans.-Unatt.	345.00	115.00	
16	Pochassic 37R, Westfield	Trans.-Unatt.	115.00	69.00	
17	Shawinigan 55E, Chicopee	Trans.-Unatt.	115.00		
18	South Agawam 42E, Agawam	Trans.-Unatt.	115.00		
19					
20	Total		21760.70	5528.36	57.80
21					
22		Distribution			
23		Transmission			
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
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40					

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
						1
150	2					2
150	2					3
250	4					4
20	3					5
17	2					6
20	2					7
23	3					8
60	3		Capacitors	2	11	9
19	3					10
15	2		Capacitors	1	5	11
21	3					12
26	3					13
13	2					14
22	4					15
25	3					16
30	3		Capacitors	3	4	17
20	3					18
27	3					19
19	3					20
250	4		Capacitors	4	40	21
26	3					22
15	2					23
80	2		Capacitors	1	5	24
14	2					25
150	2		Capacitors	4	40	26
195	3		Capacitors	4	40	27
178	4	1	Capacitors	4	40	28
150	2		Capacitors	1	63	29
			Ph Angle Reg Xfrm	2	330	30
20	2					31
181	3					32
20	1					33
24	3					34
14	2					35
188	3		Capacitors	2	11	36
30	3					37
175	3					38
160	2		Capacitors	6	32	39
20	3					40

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
125	2		Capacitors	3	74	1
188	3		Capacitors	1	63	2
109	2		Capacitors	2	19	3
80	2					4
15	3					5
20	1					6
215	3		Capacitors	2	11	7
15	3					8
						9
250	4					10
10	2					11
15	2					12
10	2					13
31	3					14
195	3		Capacitors	3	30	15
10	2					16
30	3					17
160	2		Capacitors	3	74	18
13	2					19
10	2					20
10	2					21
10	2					22
						23
270	3		Capacitors	2	19	24
						25
128	2		Capacitors	2	57	26
15	3					27
250	4		Capacitors	4	40	28
15	3					29
13	2					30
						31
15	2					32
10	2					33
17	2					34
162	3					35
250	4		Capacitors	2	206	36
160	2		Capacitors	1	5	37
19	2					38
125	2					39
100	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
20	2					1
188	3		Capacitors	1	5	2
20	2					3
19	2					4
						5
187	3					6
15	2					7
80	2		Capacitors	1	63	8
125	2					9
250	2					10
						11
11	2					12
188	3					13
265	2					14
25	2					15
188	3		Capacitors	1	35	16
250	2					17
250	2					18
28	3					19
250	2		Capacitors	4	40	20
15	2					21
250	2		Capacitors	1	37	22
180	3	1	Capacitors	3	18	23
140	2					24
79	2		Capacitors	1	35	25
100	2		Capacitors	2	10	26
40	1					27
125	2		Capacitors	2	10	28
39	1					29
40	2					30
30	2					31
48	2					32
50	1					33
100	2		Capacitors	2	10	34
50	1		Capacitors	1	2	35
50	1		Capacitors	1	5	36
40	2	1	Capacitors	2	10	37
100	2		Capacitors	2	10	38
100	2					39
50	1		Capacitors	1	5	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
25	2					1
21	2					2
11	2					3
10	2					4
168	3					5
210	3					6
188	3					7
50	1		Capacitors	1	5	8
50	1		Capacitors	1	5	9
50	1		Capacitors	1	5	10
150	3		Capacitors	2	10	11
50	1		Capacitors	1	5	12
100	2		Capacitors	3	45	13
175	3		Capacitors	3	49	14
100	2		Capacitors	3	26	15
52	2		Capacitors	2	10	16
100	2		Capacitors	3	23	17
						18
96		2				19
20	1					20
557	306	12				21
			Reactors	2	80	22
400	1	1	Reactors	3	240	23
500	1	1				24
330	1	1	Reactors	2	240	25
450	1		Ph Angle Reg Xfrm	3	495	26
400	1		Reactors	1	160	27
			Reactors	4	640	28
381	1		Reactors	2	40	29
1100	2	1	Reactors	3	320	30
1000	2					31
550	1		Reactors	1	160	32
400	1					33
						34
550	1					35
600	2		Reactors	3	320	36
900	2					37
980	2					38
490	1					39
			Capacitors	1	35	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
			Capacitors	1	30	1
			Static Var Comp	1	112	2
1415	3	1				3
						4
						5
1368	6					6
93	2		Capacitor	2	101	7
94	2					8
25	1					9
893	2					10
25	1					11
55	2					12
90	3					13
90	3		Capacitor	5	22	14
77	2					15
72	2		Capacitor	2	11	16
153	3		Capacitor	2	11	17
93	2					18
30	1					19
88	2					20
1330	6					21
30	1	1				22
60	3		Capacitor			23
15	2		Isolation			24
53	2	1				25
123	3		Capacitor	2	11	26
93	2					27
25	1					28
92	2					29
5	1					30
90	3		Capacitor	2	29	31
97	2					32
6	1					33
93	2					34
93	2					35
92	2		Capacitor	4	25	36
50	2		Capacitor	3	35	37
14	2					38
16	2					39
5	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
10	3					1
15	3					2
1	3					3
9	2					4
4	1					5
						6
8	1					7
1	1					8
						9
4	1					10
						11
						12
						13
						14
657	1					15
92	1					16
						17
						18
						19
28930	724	24		153	4,814	20
						21
17735	699	19	Capacitors	126	1,677	22
11195	25	5	Reactors	21	2,200	23
			Ph Angle Reg Xfrmr	5	825	24
			Static Car Comp	1	112	25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

FOOTNOTE DATA

Schedule Page: 426 Line No.: 2 Column: b

Distribution and Unattended

Schedule Page: 426.3 Line No.: 22 Column: b

Transmission and Unattended

Schedule Page: 426.4 Line No.: 6 Column: b

Distribution, Unattended, With Transmission Lines

Schedule Page: 426.4 Line No.: 6 Column: g

2 Banks; 3 Single Phase each bank

Schedule Page: 426.4 Line No.: 21 Column: g

2 Banks; 3 Single Phase each bank

Schedule Page: 426.4 Line No.: 38 Column: b

Distribution, Unattended, With No Transmission Lines

Schedule Page: 426.5 Line No.: 1 Column: c

Spare

Schedule Page: 426.5 Line No.: 6 Column: a

Represents a de-energized site that is not yet closed down.

Schedule Page: 426.5 Line No.: 9 Column: a

Represents a de-energized site that is not yet closed down.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				
5	General Services in a holding company system	Eversource Energy Service Company	Various (see note)	297,515,124
6				
7				
8	Storm Outage Support	Public Service Co. New Hampshire	402	4,418,084
9				
10	Storm Outage Support	The Connecticut Light and Power	402	1,578,424
11				
12	Transfer of Meters	The Connecticut Light and Power	107	2,318,509
13				
14	Transmission System Modifications	The Connecticut Light and Power	107	13,935,764
15				
16	Transfer of Transformers	The Connecticut Light and Power	107	2,707,789
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23	Storm Outage Support	Public Service Co. New Hampshire	402	291,181
24				
25	Storm Outage Support	The Connecticut Light and Power	402	5,258,562
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 5 Column: d

Service Department - Function	Account	Amount
Benefits	183	60
	228	3,478
	232	(327,211)
	401	86,596,540
	402	750
	408	9,393,641
	421	167,631
	426	288,472
	454	1,624
Benefits Total		**96,124,985**
Building Rent and Maintenance	163	69,542
	184	132,704
	232	93,846
	242	3,207
	401	6,399,409
	403	68,703
	426	20,875
	431	9,681
Building Rent and Maintenance Total		**6,797,967**
Corporate Relations	183	(9,763)
	401	4,677,388
	402	46,437
	426	1,384,111
Corporate Relations Total		**6,098,173**
Customer Group	107	3,764,086
	165	(36,429)
	183	0
	186	128,449
	401	57,292,669
	402	565,759
	417	2,718
	426	826,372
	456	(23,429)
Customer Group Total		**62,520,196**
Depreciation	403	16,704,644
Depreciation Total		**16,704,644**
Electric Distribution	107	4,557,905
	108	178,791
	163	1,578
	183	324
	184	(1,608)
	185	4,344

	401	3,906,410
	402	2,040,585
	426	240
Electric Distribution Total		**10,688,569**
Energy Supply	401	2,060,395
	402	19
Energy Supply Total		**2,060,415**
Engineering and Emergency Prep	107	4,078,093
	108	57,008
	186	88,390
	401	3,264,229
	402	66,887
Engineering and Emergency Prep Total		**7,554,607**
Enterprise Energy Strat + Bus Dev	107	111,673
	183	(5,804,756)
	184	118
	232	(693,184)
	401	534,212
	402	5,706
Enterprise Energy Strat + Bus Dev Total		**(5,846,231)**
ERM and Claims + Insurance	184	3,137
	228	584,011
	401	896,431
	402	5,694
ERM and Claims + Insurance Total		**1,489,274**
Finance and Accounting	107	2,001,913
	163	31,265
	165	(4,312)
	183	6,849
	184	36,531
	401	12,139,742
	402	152,498
	426	61
Finance and Accounting Total		**14,364,546**
General Administration	401	648,569
General Administration Total		**648,569**
Human Resources	401	4,260,891
	402	73,322
Human Resources Total		**4,334,213**
Information Technology	101	0
	107	153,973
	111	(0)
	227	0
	230	(0)

	232	32,656
	242	0
	243	0
	401	32,695,936
	402	713,515
	403	45,972
	431	5,683
Information Technology Total		**33,647,734**
Internal Audit + Security	183	(79,376)
	232	(20,540)
	401	2,206,050
Internal Audit + Security Total		**2,106,133**
Investor Relations	401	607,752
	402	955
Investor Relations Total		**608,707**
Legal	107	33,143
	108	6,517
	183	(44,808)
	228	1,026
	401	4,440,934
	402	15,152
	426	174,824
Legal Total		**4,626,788**
Miscellaneous	107	11,194,259
	108	80
	163	4,483,510
	165	154,582
	183	2,125,188
	184	627,818
	228	0
	232	242,342
	237	3,238
	401	4,153,478
	402	5,951,039
	403	(19,633,832)
	408	(9,483,851)
	417	43,141
	419	(27,706)
	421	(12,205)
	426	346,835
	432	(1,259,823)
	454	(87,657)
Miscellaneous Total		**(1,179,564)**
New Business Improvement	401	226,361
	402	17,076

New Business Improvement Total		**243,437**
Operations Administration	107	448
	401	380,921
	426	20,171
Operations Administration Total		**401,540**
Operations Services	107	22,815
	184	289,013
	401	1,781,104
	402	1,077,741
Operations Services Total		**3,170,672**
Safety	107	31
	401	1,543,265
	402	61
	426	510
Safety Total		**1,543,867**
Supply Chain + Env Affs + Property Mgmt	107	1,801,136
	108	29,928
	163	5,634,921
	183	(2,432,196)
	184	712,219
	186	22,050
	228	94,009
	232	35,269
	253	10,890
	401	8,926,978
	402	2,650,219
	417	46,615
	421	286
	454	8
Supply Chain + Env Affs + Property Mgmt Total		**17,532,332**
Taxes	184	1,009
	401	(149,692)
	408	273,937
Taxes Total		**125,254**
Transmission	107	7,908,284
	108	26,342
	183	97,343
	184	(15)
	186	44,771
	401	2,950,539
	402	120,893
	426	140
Transmission Total		**11,148,297**
Grand Total		**297,515,124**

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DEPARTMENT OF PUBLIC UTILITIES

This statement is filed in accordance with Chapter 164, Section 84A

CONDENSED FINANCIAL RETURN

FOR YEAR ENDED DECEMBER 31, 2018

NSTAR Electric Company
d/b/a Eversource Energy

800 BOYLSTON STREET

BOSTON, MA 02199

STATEMENT OF INCOME FOR THE YEAR

Item	Current Year	Increase or (Decrease) from Preceding Year
OPERATING INCOME		
Operating Revenues		
Operating Expenses:		
Operation Expense	SEE THE ATTACHED AUDITED INCOME STATEMENT FOR 2018 IN THE FERC FORM 1 FORMAT	
Maintenance Expense		
Depreciation Expense		
Amortization of Utility Plant		
Amortization of Property Losses		
Amortization of Investment Tax Credit		
Regulatory Debits, net		
Taxes other than Income Taxes		
Income Taxes		
Provisions for Deferred Federal Income Taxes		
Federal Income Taxes Deferred In Prior Years (Credit)		
Total Operating Expenses		
Net Operating Revenues		
Income from Utility Plant Leased to Others		
Other Utility Operating Income		
Total Utility Operating Income		
OTHER INCOME		
Income from Mdse. Jobbing & Contract Work		
Revenues from Merchandising, Jobbing and Contract Work		
(Less) Costs and Exp. of Merchandising, Job. & Contract Work		
Equity in Earnings of Subsidiary Companies, net		
Income from Nonutility Operations		
Nonoperating Rental Income		
Interest and Dividend Income		
Interest Charged to Construction-Debit		
Miscellaneous Nonoperating Income		
Total Other Income		
Total Income		
MISCELLANEOUS INCOME DEDUCTIONS		
Miscellaneous Amortization		
Other Income Deductions		
Total Income Deductions		
Income Before Interest Charges		
INTEREST CHARGES		
Interest on Long-Term Debt		
Amortization of Debt Discount and Expense		
Amortization of Premium on Debt-Credit		
Interest on Debt to Associated Companies		
Other Interest Expense		
Interest Charged to Construction-Credit		
Total Interest Charges		
Net Income		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	3,359,868,073	3,212,553,594		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,123,315,455	1,924,731,430		
5	Maintenance Expenses (402)	320-323	97,135,001	87,747,982		
6	Depreciation Expense (403)	336-337	268,623,877	265,031,848		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	4,730,484	7,357,498		
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)		47,943,523	34,883,593		
13	(Less) Regulatory Credits (407.4)		14,398,286	-2,096,422		
14	Taxes Other Than Income Taxes (408.1)	262-263	193,925,747	181,647,591		
15	Income Taxes - Federal (409.1)	262-263	76,519,265	111,203,256		
16	- Other (409.1)	262-263	28,549,669	26,226,916		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	180,177,048	181,008,936		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	141,611,239	72,997,470		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,789,183	-1,766,023		
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)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,891,917,933	2,747,171,979		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		467,950,140	465,381,615		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
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)	
						1
3,359,868,073	3,212,553,594					2
						3
2,123,315,455	1,924,731,430					4
97,135,001	87,747,982					5
268,623,877	265,031,848					6
						7
4,730,484	7,357,498					8
						9
						10
						11
47,943,523	34,883,593					12
-14,398,286	-2,096,422					13
193,925,747	181,647,591					14
76,519,265	111,203,256					15
28,549,669	26,226,916					16
180,177,048	181,008,936					17
141,611,239	72,997,470					18
-1,789,183	-1,766,023					19
						20
						21
						22
						23
						24
2,891,917,933	2,747,171,979					25
467,950,140	465,381,615					26

Name of Respondent NSTAR Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2018/Q4

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)		467,950,140	465,381,615		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		848,031	1,036,862		
34	(Less) Expenses of Nonutility Operations (417.1)		595,041	674,950		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-4,266,853	-9,327,855		
37	Interest and Dividend Income (419)		803,850	1,850,186		
38	Allowance for Other Funds Used During Construction (419.1)		[redacted]	10,175,401		
39	Miscellaneous Nonoperating Income (421)		17,869,524	19,546,935		
40	Gain on Disposition of Property (421.1)		547,851	105,077		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		30,324,510	22,711,656		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		389,847	489,566		
46	Life Insurance (426.2)		-210,150	-3,243,667		
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		644,481	731,277		
49	Other Deductions (426.5)		[redacted]	4,426,646		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,828,651	2,403,822		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	336,731	311,528		
53	Income Taxes-Federal (409.2)	262-263	-1,747,842	-1,512,200		
54	Income Taxes-Other (409.2)	262-263	-407,937	-83,848		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	9,676,153	6,609,744		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	84,921	130,457		
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)		7,772,184	5,194,767		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		20,723,675	15,113,067		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		111,682,568	118,552,013		
63	Amort. of Debt Disc. and Expense (428)		[redacted]	3,656,868		
64	Amortization of Loss on Reaquired Debt (428.1)		[redacted]	681,150		
65	(Less) Amort. of Premium on Debt-Credit (429)		[redacted]	1,631,504		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)			817,168		
68	Other Interest Expense (431)		-1,598,931	-11,528,597		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		7,296,852	4,776,393		
70	Net Interest Charges (Total of lines 62 thru 69)		105,583,663	105,768,705		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		383,090,152	374,725,977		
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)		383,090,152	374,725,977		

Schedule Page: 114 Line No.: 13 Column: c

Ferc Account	Company	Ending Balance
407.4	NSTAR Electric East	$ 335,421
	West	(14,733,707)
407.4 Total		**$ (14,398,286)**

Schedule Page: 114 Line No.: 19 Column: c

Ferc Account	Company	Ending Balance
411.4	NSTAR Electric East	$ (1,151,351)
	West	(637,832)
411.4 Total		**$ (1,789,183)**

Schedule Page: 114 Line No.: 38 Column: c

Ferc Account	Company	Ending Balance
419.1	NSTAR Electric East	$ 14,920,641
	West	196,507
419.1 Total		**$ 15,117,148**

Schedule Page: 114 Line No.: 49 Column: c

Note that for the year ended December 31, 2018, the total amount of Public Education expenses in Account 426.5 includes a transmission related component of $0.

Schedule Page: 114 Line No.: 63 Column: c

Ferc Account	Company	Ending Balance
428	NSTAR Electric East	$ 2,313,452
	West	1,304,115
428 Total		**$ 3,617,567**

Schedule Page: 114 Line No.: 64 Column: c

Ferc Account	Company	Ending Balance
428.1	NSTAR Electric East	$ 606,648
	West Distribution	24,834
	West Transmission	49,668
428.1 Total		**$ 681,150**

FOOTNOTE DATA

Schedule Page: 114 Line No.: 65 Column: c

Ferc Account	Company	Ending Balance
429	NSTAR Electric East	$ 428,400
	West	1,073,439
429 Total		**$ 1,501,839**

BALANCE SHEET

Title of Account	Balance End of Year
UTILITY PLANT	
Utility Plant	
OTHER PROPERTY AND INVESTMENTS	
Nonutility Property	
Investment in Associated Companies	
Other Investments	
Special Funds	
Total Other Property and Investments	
CURRENT AND ACCRUED ASSETS	
Cash	
Special Deposits	
Working Funds	
Temporary Cash Investments	
Notes and Accounts Receivable	
Receivables from Associated Companies	
Materials and Supplies	
Allowances	
Prepayments	
Rents Receivable	
Accrued Utility Revenues	
Misc. Current and Accrued Assets	
Total Current and Accrued Assets	
DEFERRED DEBITS	
Unamortized Debt Discount and Expense	
Temporary facilities	
Unamortized Loss on Reacquired Debt	
Reserve for Deferred Income Taxes	
Regulatory Assets	
Miscellaneous Deferred Debits	
Total Deferred Debits	
CAPITAL STOCK DISCOUNT AND EXPENSE	
Discount on Capital Stock	
Capital Stock Expense	
Total Capital Stock Discount and expense	
REACQUIRED SECURITIES	
Reacquired Capital Stock	
Reacquired Bonds	
Total Reacquired Securities	
Total Assets and Other Debits	

Title of Account	Balance End of Year
PROPRIETARY CAPITAL	
CAPITAL STOCK	
Common Stock Issued	
Preferred Stock Issued	
Capital Stock Subscribed	
Premium on Capital Stock	
Total	
SURPLUS	
Other Paid-In Capital	
Earned Surplus	
Surplus Invested in Plant	
Total	
Total Propriety Capital	
LONG-TERM DEBT	
Bonds	
Advances from Associated Companies	
Other Long-Term Debt	
Total Long-Term Debt	
OTHER NON CURRENT LIABILITIES	
Asset Retirement Obligations	
Accumulated Provision for Pensions and Benefits	
Total Other Noncurrent Obligations	
CURRENT AND ACCRUED LIABILITIES	
Notes Payable	
Accounts Payable	
Payables to Associated Companies	
Customer Deposits	
Taxes Accrued	
Interest Accrued	
Dividends Declared	
Matured Long-Term Debt	
Matured Interest	
Tax Collections Payable	
Misc. Current and Accrued Liabilities	
Total Current and Accrued Liabilities	
DEFERRED CREDITS	
Acc. Deferred Investment Tax Credit	
Unamortized Premium on Debt	
Customer Advances for Construction	
Regulatory Liabilities	
Other Deferred Credits	
Total Deferred Credits	
RESERVES	
Reserves for Depreciation	
Reserves for Amortization	
Reserves for Uncollectible Accounts	
Operating Reserves	
Reserve for Depreciation and Amortization of Nonutility Property	
Reserves for Deferred Income Taxes	
Total Reserves	
CONTRIBUTIONS IN AID OF CONSTRUCTION	
Contributions in Aid of Construction	
Total Liabilities and Other Credits	

NOTES: SEE THE ATTACHED AUDITED BALANCE SHEET FOR 2018 IN THE FERC FORM 1 FORMAT.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	[illegible]	10,301,966,288
3	Construction Work in Progress (107)	200-201	[illegible]	447,851,109
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		11,402,328,699	10,749,817,397
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,967,931,831	2,802,914,195
6	Net Utility Plant (Enter Total of line 4 less 5)		8,434,396,868	7,946,903,202
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)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		8,434,396,868	7,946,903,202
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		4,858,250	5,030,847
19	(Less) Accum. Prov. for Depr. and Amort. (122)		94,887	92,740
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	16,024,653	6,791,505
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)		901,590	1,008,883
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		132,809,645	126,948,028
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)		154,499,251	139,686,523
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		0	0
36	Special Deposits (132-134)		13,054,421	12,917,853
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		299,302,350	279,632,436
41	Other Accounts Receivable (143)		134,848,169	125,933,178
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		74,411,265	69,561,390
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		32,582,097	41,403,616
45	Fuel Stock (151)	227	0	0
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	61,693,671	49,531,530
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	[illegible]	[illegible]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	45,571	391,487
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)		[illegible]	11,963,323
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		107,588	73,730
60	Rents Receivable (172)		1,449,638	5,195,312
61	Accrued Utility Revenues (173)		34,517,648	49,864,790
62	Miscellaneous Current and Accrued Assets (174)		0	0
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)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		609,804,775	557,737,786
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		[illegible]	19,455,830
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	[illegible]	[illegible]
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,267,208	373,635
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)		303	-92,034
77	Temporary Facilities (185)		-522,765	-1,270,673
78	Miscellaneous Deferred Debits (186)	233	90,022,171	76,809,391
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)		[illegible]	11,319,222
82	Accumulated Deferred Income Taxes (190)	234	462,181,372	398,218,981
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,010,567,051	2,009,664,104
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		11,209,267,945	10,653,991,615

Schedule Page: 110 Line No.: 2 Column: c

In the third quarter of 2018, management identified and corrected a $1.1 million error related to retirements that resulted in a misclassification as of December 31, 2017 between accounts 101 and 108.

Schedule Page: 110 Line No.: 3 Column: c

WEST:
Information on Formula Rates:
Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Schedule Page: 110 Line No.: 52 Column: c

Represents the value of Renewable Energy Certificates (RECs) that NSTAR Electric Company uses to meet the Commonwealth of Massachusetts' Renewable Portfolio Standards requirements. These RECs are recorded in Account 158.3.

Schedule Page: 110 Line No.: 52 Column: d

Represents the value of Renewable Energy Certificates (RECs) that NSTAR Electric Company uses to meet the Commonwealth of Massachusetts' Renewable Portfolio Standards requirements. These RECs are recorded in Account 158.3.

Schedule Page: 110 Line No.: 57 Column: c

At December 31, 2018, the total Prepayments balance in Account 165 includes NSTAR Electric East related prepayments of the following amounts:

Prepaid State Taxes	$ 6,309,081	dr.
Prepaid Insurance	1,824,792	dr.
Prepaid Interest	89,097	dr.
Prepaid Lease	80,133	dr.
Prepaid Workers Comp.	638,600	dr.
Prepaid Agency Fees	518,788	dr.
Prepaid Postage	33,600	dr.
Prepaid Federal Taxes	26,592,632	dr.
Prepaid Other	28,628	dr.
	$ 36,115,352	dr.

At December 31, 2018, the total Prepayments balance in Account 165 includes NSTAR Electric West related prepayments of the following amounts:

Prepaid State Taxes	1,415,621	dr.
Prepaid Insurance	374,546	dr.
Prepaid Lease	70,874	dr.
Prepaid Workers Comp.	212,060	dr.
Prepaid Software License Maint.	62,220	dr.
Prepaid Vehicle Property Taxes	45,256	dr.
Prepaid Vehicle Costs	92,736	dr.
Prepaid Federal Taxes	2,625,382	dr.
Prepaid Other	6,725	dr.
	$ 4,905,420	dr.

At December 31, 2018, the total Prepayments balance in Account 165 includes NSTAR Electric West transmission related prepayments of the following amounts:

Prepaid State Taxes	$ 1,524,190	dr.
Prepaid Federal Taxes	(7,932,969)	cr.
Prepaid Insurance	157,140	dr.
Prepaid Lease	(500)	cr.
Prepaid Software License Maint.	15,555	dr.
Prepaid Other	5,516	dr.
Total	$ (6,231,068)	cr.

Schedule Page: 110 Line No.: 69 Column: c

At December 31, 2018, the total Unamortized Debt Expenses balance in Account 181 includes NSTAR Electric East related Debt of the following amounts:

Debentures Due 03/2044	$ 2,571,563	dr.
Debentures Due 03/2036	1,252,508	dr.
Debentures Due 03/2040	2,214,080	dr.
Debentures Due 10/2022	1,208,859	dr.
Debentures Due 11/2025	1,467,011	dr.
Debentures Due 06/2026	1,581,921	dr.
Debentures Due 05/2027	5,421,260	dr.
DPU Financing Plan	120,600	dr.
Total	$ 15,837,802	dr.

At December 31, 2018, the total Unamortized Debt Expenses balance in Account 181 includes NSTAR Electric West related Debt of the following amounts:

Series E. Due 03/2020	$ 115,801	dr.
Series G. Due 11/2023	220,279	dr.
Series H. Due 06/2026	230,720	dr.
Series F. Due 09/2021	642,725	dr.
Series D. Due 08/2037	311,081	dr.
Series B. Due 09/2034	286,923	dr.
	$ 1,807,529	dr.

Schedule Page: 110 Line No.: 72 Column: c

For Form 1 reporting purposes, the following reclassification of debit or credit balance accounts at December 31, 2018 are being included with Account 182.3 - Other Regulatory Assets. The balances are as follows:

Balance in Account 182.3	1,221,308,267	dr.
Reclass of balances to Account 254: Mitigation Incentive Timing - DPU 05-89	314,352	dr.
Reclass of balances to Account 254: Pension and PBOP	33,542,425	dr.
Reclass of balances from Account 254: Basic Service Adder True up	124,429	cr.

Reclass of balances from Account 254: Deferred Transition Rev BECO	639,186 cr.
Reclass of balances to Account 254: Deferred Basic Service	4,518,390 dr.
Reclass of balances to Account 254: Deferred Transmission Revenues	88,984,023 dr.
Reclass of balances from Account 254: Deferred NSTAR Green	128,418 cr.
Reclass of balances to Account 254: Reg Asset Revenue Decoupling	717,159 dr.
Reclass of balances to Account 254: Deferred DSM Revenue	66,942,442 dr.
Reclass of balances to Account 254: Deferred Metering Costs	12,735,130 dr.
Reclass of balances to Account 254: Uncollectibles Assoc with Basic Service	181,536 dr.
Reclass of balances from Account 254: Protective Hardship Credit	16,332 cr.
Account 182.3 Being Reported	1,428,335,359 dr.

Schedule Page: 110 Line No.: 72 Column: d

For Form 1 reporting purposes, the following reclassification of debit or credit balance accounts at December 31, 2017 are being included with Account 182.3 - Other Regulatory Assets. The balances are as follows:

Balance in Account 182.3	$	1,309,814,848 dr.
Reclass of balances from Account 254: Deferred Energy Efficiency		134,250,783 dr.
Reclass of balances to Account 254: Transition Reconciliation		5,730,439 dr.
Reclass of balances from Account 254: Basic Service Uncollectibles		21,513 cr.
Reclass of balances to Account 254: Deferred Transmission Revenues		14,941,252 dr.
Reclass of balances to Account 254: Pension and PBOP		40,133,963 dr.
Account 182.3 Being Reported	$	1,504,849,772 dr.

FOOTNOTE DATA

Schedule Page: 110 Line No.: 81 Column: c

Ferc Account	Company	Ending Balance
189	East Distribution	10,439,401
	West Distribution	66,224
	West Transmission	132,447
189 Total		**10,638,072**

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	*(mo, da, yr)* / /	end of 2018/Q4

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	[redacted]	[redacted]
3	Preferred Stock Issued (204)	250-251	[redacted]	[redacted]
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		3,905,151	3,905,151
7	Other Paid-In Capital (208-211)	253	2,814,604,083	2,684,104,083
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	924,875,880	767,478,875
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-11,851,691	-7,584,838
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)	-1,378,596	-1,824,103
16	Total Proprietary Capital (lines 2 through 15)		[redacted]	[redacted]
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	[redacted]	[redacted]
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	[redacted]	[redacted]
22	Unamortized Premium on Long-Term Debt (225)		[redacted]	7,934,344
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		[redacted]	9,719,241
24	Total Long-Term Debt (lines 18 through 23)		[redacted]	2,963,215,103
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		3,442,730	3,754,457
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		45,644,076	37,562,761
29	Accumulated Provision for Pensions and Benefits (228.3)		19,113,908	94,156,648
30	Accumulated Miscellaneous Operating Provisions (228.4)		7,247,160	2,701,959
31	Accumulated Provision for Rate Refunds (229)		2,977,239	2,977,239
32	Long-Term Portion of Derivative Instrument Liabilities		0	176,612
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		63,400,062	44,574,835
35	Total Other Noncurrent Liabilities (lines 26 through 34)		141,825,175	185,904,511
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		278,500,000	234,000,000
38	Accounts Payable (232)		369,724,650	329,786,653
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		85,933,152	91,791,910
41	Customer Deposits (235)		8,002,577	8,195,387
42	Taxes Accrued (236)	262-263	5,889,025	12,127,449
43	Interest Accrued (237)		25,526,493	25,515,271
44	Dividends Declared (238)		489,998	489,998
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2018/Q4

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)		3,892,582	3,875,632
48	Miscellaneous Current and Accrued Liabilities (242)		278,161,382	228,387,970
49	Obligations Under Capital Leases-Current (243)		310,693	319,752
50	Derivative Instrument Liabilities (244)		123,106	1,232,421
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	176,611
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,056,553,658	935,545,832
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		47,196,139	52,386,151
57	Accumulated Deferred Investment Tax Credits (255)	266-267	31,935,098	10,671,434
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	52,778,123	42,391,952
60	Other Regulatory Liabilities (254)	278	[illegible]	[illegible]
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)		1,261,473,709	1,191,923,425
64	Accum. Deferred Income Taxes-Other (283)		507,580,455	486,510,252
65	Total Deferred Credits (lines 56 through 64)		3,275,242,797	3,080,246,801
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		11,209,267,945	10,653,991,615

Schedule Page: 112 Line No.: 2 Column: c

Information on Formula Rates:

EAST:

Page 106.2 line 1 Amount stipulated per contract.

Schedule Page: 112 Line No.: 2 Column: d

Information on Formula Rates:

EAST:

Page 106.2 line 1 Amount stipulated per contract.

Schedule Page: 112 Line No.: 3 Column: c

	Total	East	West
Total of Preferred Stock	43,000,000	43,000,000	0

EAST:

Page 106 lines 16, 19 Amount stipulated per contract.

Page 106.2 lines 1, 5 Amount stipulated per contract

Schedule Page: 112 Line No.: 3 Column: d

Information on Formula Rates:

EAST:

Page 106 lines 16, 19 Amount stipulated per contract.

Page 106.2 lines 1, 5 Amount stipulated per contract

Schedule Page: 112 Line No.: 16 Column: c

	Total	East	West
Total Proprietary Capital	3,773,155,027	3,053,220,505	719,934,522

Information on Formula Rates:

EAST:

Page 106.2 lines 1, 5 Amount stipulated per contract.

Schedule Page: 112 Line No.: 16 Column: d

Information on Formula Rates:

EAST:

Page 106.2 lines 1, 5 Amount stipulated per contract.

Schedule Page: 112 Line No.: 18 Column: c

Information on Formula Rates:

Page 106.2 lines 1, 5 Amount stipulated per contract.

Schedule Page: 112 Line No.: 18 Column: d

Information on Formula Rates:

Page 106.2 lines 1, 5 Amount stipulated per contract.

Schedule Page: 112 Line No.: 21 Column: c

Information on Formula Rates:

EAST:

Page 106 lines 16, 19 — Amount stipulated per contract.

Page 106.2 lines 1, 5 — Amount stipulated per contract.

Schedule Page: 112 Line No.: 21 Column: d

Information on Formula Rates:

EAST:

Page 106 lines 16, 19 — Amount stipulated per contract.

Page 106.2 lines 1, 5 — Amount stipulated per contract.

Schedule Page: 112 Line No.: 22 Column: c

	Total	East	West
Total Unamortized Premium on Long-Term Debt	6,432,505	3,570,000	2,862,505

Schedule Page: 112 Line No.: 23 Column: c

	Total	East	West
Total of Unamortized Discount on Long-Term Debt	8,941,217	8,451,562	489,655

Schedule Page: 112 Line No.: 24 Column: c

	Total	East	West
Total of Long-Term Debt	2,962,491,288	2,395,118,438	567,372,850

Schedule Page: 112 Line No.: 60 Column: c

For Form 1 reporting purposes, the following reclassification of debit or credit balance accounts at December 31, 2018 are being included with Account 254 - Other Regulatory Liabilities. The balances are as follows:

Balance in Account 254	1,167,252,181	cr.
Reclass of balances from Account 182.3: Mitigation Incentive Timing - DPU 05-89	314,352	cr.
Reclass of balances from Account 182.3: Pension and PBOP	33,542,425	cr.
Reclass of balances to Account 182.3: Basic Service Adder True up	124,429	dr.
Reclass of balances to Account 182.3: Deferred Transition Rev BECO	639,186	dr.
Reclass of balances from Account 182.3: Deferred Basic Service	4,518,390	cr.
Reclass of balances from Account 182.3: Deferred Transmission Revenues	88,984,023	cr.
Reclass of balances to Account 182.3: Deferred NSTAR Green	128,418	dr.

Reclass of balances from Account 182.3: Reg Asset Revenue Decoupling	717,159 cr.
Reclass of balances from Account 182.3: Deferred DSM Revenue	66,942,442 cr.
Reclass of balances from Account 182.3: Deferred Metering Costs	12,735,130 cr.
Reclass of balances from Account 182.3: Uncollectibles Assoc with Basic Service	181,536 cr.
Reclass of balances to Account 182.3: Protective Hardship Credit	16,332 dr.
Account 254 Being Reported	1,374,279,273 cr.

Schedule Page: 112 Line No.: 60 Column: d

For Form 1 reporting purposes, the following reclassification of debit or credit balance accounts at December 31, 2017 are being included with Account 254 - Other Regulatory Liabilities. The balances are as follows:

Balance in Account 254	1,101,328,663 cr.
Reclass of balances to Account 182.3: Deferred Energy Efficiency	134,250,783 cr.
Reclass of balances from Account 182.3: Transition Reconciliation	5,730,439 cr.
Reclass of balances to Account 182.3: Basic Service Uncollectibles	21,513 dr.
Reclass of balances from Account 182.3: Deferred Transmission Revenues	14,941,252 cr.
Reclass of balances from Account 182.3: Pension and PBOP	40,133,963 cr.
Account 254 Being Reported	1,296,363,587 cr.

STATEMENT OF EARNED SURPLUS

Account	Amount for Year	Inc/(Dec) from Preceding Year
Unappropriated Earned Surplus (at beginning of period)	$759,894,037	$100,765,978
Balance Transferred from Income	383,090,152	8,364,175
Miscellaneous Credits to Surplus		0
Miscellaneous Debits to Surplus		
Appropriations of Surplus		
Net Additions to Earned Surplus	383,090,152	8,364,175
Dividends Declared-Preferred Stock	1,960,000	0
Dividends Declared-Common Stock	228,000,000	(44,000,000)
Unappropriated Earned Surplus (at end of period)	$913,024,189	$153,130,153

ELECTRIC OPERATING REVENUES

Account	Operating Revenues	
	Amount for Year	Inc/(Dec) from Preceding Year
SALES OF ELECTRICITY		
Residential Sales	$1,383,550,022	$113,799,656
Commercial and Industrial Sales		
Small (or Commercial)	1,375,030,078	110,671,371
Large (or Industrial)	124,894,540	10,928,221
Public Street and Highway Lighting	14,599,693	820
Other Sales to Public Authorities		
Sales to Railroad and Railways		
Interdepartmental Sales		
Miscellaneous Electric Sales		
Total Sales to Ultimate Consumers	2,898,074,333	235,400,068
Sales for Resale	73,125,096	(3,962,285)
Less: Provision for Rate Refunds	(5,255,654)	(8,254,113)
Total Sales of Electricity	2,976,455,083	239,691,896
OTHER OPERATING REVENUES		
Forfeited Discounts	4,510,904	193,678
Miscellaneous Service Revenues	1,611,900	1,296,110
Sales of Water and Water Power		
Rent from Electric Property	14,484,140	1,406,770
Interdepartmental Rents		
Other Electric Revenues	362,806,046	(95,273,975)
Total Other Operating Revenues	383,412,990	(92,377,417)
Total Electric Operating Revenues	$3,359,868,073	$147,314,479

SUMMARY OF ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Functional Classification	Operation	Maintenance	Total
Power Production Expenses	$	$	$
Electric Generation			
Steam Power			
Nuclear Power			
Hydraulic Power			
Other Power			
Other Power Supply Expenses	1,060,819,848		1,060,819,848
Total Power Production Expenses	1,060,819,848	0	1,060,819,848
Transmission Expenses..(Note)	452,054,793	15,359,335	467,414,128
Distribution Expenses	62,418,136	81,754,435	144,172,571
Customer Accounts Expenses	405,398,885		405,398,885
Sales Expenses	39,030		39,030
Administrative and General Expenses	142,584,763	21,231	142,605,994
Total Electric Operation and Maintenance Expenses	$2,123,315,455	$97,135,001	$2,220,450,456

Note: Includes $278,766 Regional Transmission and Market Op Expense

GAS OPERATING REVENUES

Account	Operating Revenues	
	Amount for Year	Increase or (Decrease) from Preceding Year
SALES OF GAS	NONE	NONE
Residential Sales		
Commercial and Industrial Sales		
Small (or Commercial)		
Large (or Industrial)		
Other Sales to Public Authorities		
Interdepartmental Sales		
Miscellaneous Gas Sales		
Total Sales to Ultimate Consumers	NONE	NONE
Sales for Resale		
Total Sales of Gas	NONE	NONE
OTHER OPERATING REVENUES		
Miscellaneous Service Revenues		
Revenues from Transportation of Gas to Others		
Sales of Products Extracted from Natural Gas		
Revenues from Natural Gas Processed by Others		
Rent from Gas Property		
Interdepartmental Rents		
Other Gas Revenues		
Total Other Operating Revenues	NONE	NONE
Total Gas Operating Revenues	NONE	NONE

SUMMARY OF GAS OPERATION AND MAINTENANCE EXPENSES

Functional Classification	Operation	Maintenance	Total
Steam Production	NONE	NONE	NONE
Manufactured Gas Production			
Other Gas Supply Expenses			
Total Production Expenses	NONE	NONE	NONE
Local Storage Expenses			
Transmission and Distribution Expense			
Customer Accounts Expense			
Sales Expense			
Administrative and General Expenses			
Total Gas Operation and Maintenance Expenses	NONE	NONE	NONE

April 12, 2019, I hereby certify that the foregoing statements are full, just and true to the best of my knowledge and belief. This statement is signed under the penalties of perjury.

John M. Moreira - Senior Vice President-Finance and Regulatory and Treasurer

Jay S. Buth - Vice President, Controller and Chief Accounting Officer

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
NSTAR Electric Company	End of 2018/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of _____ , we have also reviewed schedules _____of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the

termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

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.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; .....

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

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

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/Period of Report
NSTAR Electric Company	End of 2018/Q4

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)*
800 Boylston Street, Boston, Massachusetts 02199

05 Name of Contact Person	06 Title of Contact Person
Carla J. Dacey	Manager-Rev & Reg Accounting

07 Address of Contact Person *(Street, City, State, Zip Code)*
247 Station Drive, SUM NE-230, Westwood, Massachusetts 02090-9230

08 Telephone of Contact Person,*Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(781) 441-8816	(1) [X] An Original (2) [ ] A Resubmission	/ /

ANNUAL 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)*
Jay S. Buth		
02 Title	Jay S. Buth	04/12/2019
Vice President, Controller and CAO		

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
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	Not Applicable
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	Not Applicable
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	Not Applicable
25	Unrecovered Plant and Regulatory Study Costs	230	Not Applicable
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	Not Applicable
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	Not Applicable
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	Not Applicable
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	Not Applicable
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	Not Applicable
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	Not Applicable
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	Not Applicable
64	Hydroelectric Generating Plant Statistics	406-407	Not Applicable
65	Pumped Storage Generating Plant Statistics	408-409	Not Applicable
66	Generating Plant Statistics Pages	410-411	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	None
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [ ] Two copies will be submitted [X] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	*(Mo, Da, Yr)* / /	End of 2018/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Jay S. Buth, Vice President, Controller and Chief Accounting Officer
NSTAR Electric Company
107 Selden Street
Berlin, CT 06037

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Incorporated in Massachusetts in January, 1886.

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

N/A

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Delivery of electricity in the state of Massachusetts.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report *(Mo, Da, Yr)*	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Name of Controlling Organization: Eversource Energy, a Massachusetts business trust and voluntary association headquartered in Boston, Massachusetts and Hartford, Connecticut, is a public utility holding company subject to regulation by the FERC under the Public Utility Company Holding Act of 2005, which wholly and directly owns the respondent.

Manner in Which Control was Held: Ownership of Common Stock

Extent of Control: 100%

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Harbor Electric Energy Company	Electric utility	100%	
2				
3	Yankee Atomic Electric Company	Nuclear electric generation	21%	
4		(unit permanently closed)		
5				
6	Connecticut Yankee Atomic Power Company	Nuclear electric generation	23.5%	
7		(unit permanently closed)		
8				
9	Maine Yankee Atomic Power Company	Nuclear electric generation	7%	
10		(unit permanently closed)		
11				
12	New England Hydro-Transmission Elec., Co., Inc	Electric transmission		(1)
13				
14	New England Hydro-Transmission Corporation	Electric transmission		(1)
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18				
19	(1) The Company owns 14.47% of the common			
20	stock with a 7.9% voting interest.			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chairman	James J. Judge	
2	Chief Executive Officer	Werner J. Schweiger	
3	President and Chief Operating Officer	Craig A. Hallstrom	
4	Executive Vice President and General Counsel	Gregory B. Butler	
5	Executive Vice President and Chief Financial Officer	Philip J. Lembo	
6	Senior Vice President-Finance and Regulatory		
7	and Treasurer	John M. Moreira	
8	Senior Vice President-Transmission	Kathleen A. Shea	
9	Vice President-Supply Chain, Environmental Affairs		
10	and Property Management	Ellen K. Angley	
11	Vice President, Controller and Chief Accounting Officer	Jay S. Buth	
12	Vice President-Energy Supply	James G. Daly	
13	Vice President-Electric Field Operations	Douglas W. Foley	
14	Vice President-Electric System Operations	Michael F. Hayhurst	
15	Vice President-Station Operations and		
16	Field Engineering/Communications	Joseph D. Luchini	
17	Vice President-Engineering	Paul R. Renaud	
18	Vice President-Rates and Regulatory Requirements		
19	and Treasurer	Christine L. Vaughan	
20	Secretary and Clerk	Richard J. Morrison	
21			
22	See Footnotes for Page 104 for changes to		
23	incumbents made during the year.		
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25	Salaries are not disclosed as they are paid by		
26	Eversource Energy Service Company.		
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FOOTNOTE DATA

Schedule Page: 104 Line No.: 7 Column: b

John M. Moreira was elected Senior Vice President-Finance and Regulatory and Treasurer, effective September 12, 2018.

Schedule Page: 104 Line No.: 8 Column: b

Kathleen A. Shea resigned as Senior Vice President-Transmission, effective May 4, 2018.

Schedule Page: 104 Line No.: 16 Column: b

Joseph D. Luchini, formerly Vice President-Station Operations and Field Engineering/Communications, passed away unexpectedly on July 3, 2018.

Schedule Page: 104 Line No.: 17 Column: b

Paul R. Renaud resigned as Vice President-Engineering, effective April 9, 2018.

Schedule Page: 104 Line No.: 19 Column: b

Christine M. Vaughan, formerly Vice President-Rates and Regulatory Requirements and Treasurer, resigned effective July 27, 2018.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Gregory B. Butler	56 Prospect Street, Hartford, CT 06103
2	(Executive Vice President and General Counsel)	
3		
4	James J. Judge (Chairman)	800 Boylston Street, Boston, MA 02199
5		
6	Philip J. Lembo	800 Boylston Street, Boston, MA 02199
7	(Executive Vice President and Chief Financial Officer)	
8		
9	Werner J. Schweiger (Chief Executive Officer)	107 Selden Street, Berlin, CT 06037
10		
11	The Company does not have an Executive Committee.	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	[X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	ISO New England Inc. Transmission, Markets and	ER07-549, EL07-71, ER19-123
2	Services Tariff, Section II, Schedule 21-NSTAR	
3		
4	ISO New England Inc. Transmission, Markets and	ER05-754, ER18-132
5	Services Tariff, Section II, Schedule 20A-NSTAR	
6		
7	ISO-NE Transmission, Markets and Services Tariff,	RT04-2, ER04-116, ER05-374, ER18-1722
8	Section II, Attachment F	
9		
10	NSTAR Electric Company, Rate Schedule FERC No. 210	ER07-548, ER19-431
11	(MATEP LLC - Brighton Station #329)	
12		
13	NSTAR Electric Company, Rate Schedule FERC No. 220	ER12-956
14	(MATEP LLC - Colburn Station #350)	
15		
16	NSTAR Electric Company, Rate Schedule FERC No. 205	ER10-568
17	(Massachusetts Port Authority)	
18		
19	NSTAR Electric Company (f/k/a Boston Edison	ER07-595
20	Company), Rate Schedule FERC No. 200	
21	(Massachusetts Bay Transportation Authority)	
22		
23	Space Reserved for Future Contract	
24		
25		
26	NSTAR Electric Company (f/k/a Boston Edison	ER91-149, ER86-562, ER87-232
27	Company), Rate Schedule FERC No. 169	
28	(Concord Municipal Light Plant)	
29		
30	NSTAR Electric Company (f/k/a Boston Edison	ER99-2598
31	Company), Rate Schedule FERC No. 196 (ANP	
32	Blackstone Energy Company - Annual	
33	Facilities Charge)	
34		
35	NSTAR Electric Company (f/k/a Commonwealth	ER03-1348
36	Electric Company), Service Agreement No. 27	
37	under ISO New England Inc. Transmission,	
38	Markets and Services Tariff, Section II, Schedule	
39	21-NSTAR (Entergy Nuclear Generation Company	
40	RFA Barnstable Capacitor Bank)	
41		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INFORMATION ON FORMULA RATES (continued)

FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	[X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	ISO New England Inc. Transmission, Markets and	ref. ER01-523
2	Services Tariff, Section II, Schedule 22 -	
3	LGIA, Original Service Agreement No.	
4	LGIA-ISONE/ NSTAR-15-01	
5	(Calpine Fore River Energy Center, LLC -	
6	Annual Facilities Charge)	
7		
8	NSTAR Electric Company (f/k/a Boston Edison	ER01-3138
9	Company), Service Agreement No. 73 under ISO	
10	New England Inc. Transmission, Markets and	
11	Services Tariff, Section II, Schedule 21-NSTAR	
12	(Granite Ridge (AES Londonderry) - Annual	
13	Facilities Charge)	
14		
15	NSTAR Electric Company (f/k/a Boston Edison	ER98-4332
16	Company), Rate Schedule FERC No. 193	
17	(Millennium Power Partners, L.P. - Annual	
18	Facilities Charge)	
19		
20	ISO New England Inc. Transmission, Markets and	ref. ER02-167
21	Services Tariff, Section II, Schedule 22 - LGIA,	
22	Original Service Agreement No.	
23	LGIA-ISONE/ NSTAR-12-01	
24	(Kendall Green Energy LLC -	
25	Annual Facilities Charge)	
26		
27	NSTAR Electric Company (f/k/a Boston Edison	ER06-145
28	Company), Service Agreement No. 30 under ISO	
29	New England Inc. Transmission, Markets and	
30	Services Tariff, Section II, Schedule 21-NSTAR	
31	(New England Power (Nantucket - Merchant's	
32	Way IA) - Annual Facilities Charge)	
33		
34	NSTAR Electric Company (f/k/a Boston Edison	ER06-423
35	Company), Service Agreement No. 85 under ISO	
36	New England Inc. Transmission, Markets and	
37	Services Tariff, Section II, Schedule 21-NSTAR	
38	(New England Power - Dewar Street IA)	
39		
40		
41		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INFORMATION ON FORMULA RATES (continued)
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	[X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	NSTAR Electric Company (f/k/a Boston Edison	ER89-612
2	Company), Rate Schedule FERC No. 152 (BECO	
3	HQ AC Support Agreement)	
4		
5	NSTAR Electric Company (f/k/a Boston Edison	Filed 3/31/1980
6	Company), Rate Schedule FPC No. [ ] (New	
7	England Power - Lines 255-2337 and 255-2338)	
8		
9	ISO New England Inc. Transmission, Markets and	ER14-2596
10	Services Tariff, Section II, Schedule 21-NSTAR,	
11	Original Service Agreement No. TSA-NSTAR-001	
12	(MBTA LSA - Direct Assignment Charge)	
13		
14	NSTAR Electric Company	ER18-1574
15	Service Agreement No. RFA-NSTAR-002	
16	(NSTAR - Milford Power, LLC -	
17	Annual Facilities Charge)	
18		
19		
20	NSTAR Electric Company	ER16-2189
21	Rate Schedule FERC No. 263	
22	(NSTAR - HQUS Transfer Agreement)	
23		
24	NSTAR Electric Company	ER15-1383
25	Rate Schedule FERC No. 280	
26	(NSTAR - HQUS Transfer Agreement -	
27	CMEEC Use Rights)	
28		
29	NSTAR Electric Company	ER17-235
30	Service Agreement No. FSA-NSTAR-001	
31	(National Grid Facilities Support	
32	Agreement for Edgar-Field Street)	
33		
34	NSTAR Electric Company	ER18-1170
35	Rate Schedule FERC No. TSA-NSTAR-009	
36	(NSTAR – Nalcor Energy Marketing Corporation	
37	Transfer Agreement - CMEEC Use Rights)	
38		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INFORMATION ON FORMULA RATES (continued)

FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	[X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	ISO-NE Transmission, Markets and Services Tariff,	RT04-2, ER04-116, ER18-132
2	Section II, Schedule 1, Appendix A	
3		
4	Space Reserved for Future Contract	
5		
6		
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8		
9	ISO-NE Transmission, Markets and Services Tariff,	ER03-1247, ER05-1117, ER19-122, ER19-123
10	Section II, Schedule 21-ES	
11		
12	ISO-NE Transmission, Markets and Services Tariff,	ER05-754, ER18-132
13	Section II, Schedule 20A-ES	
14		
15	NSTAR Electric Company	ER05-967, ER18-749
16	Service Agreement No. IA-NU-02	
17	(Essential Power Massachusetts, LLC)	
18		
19	NSTAR Electric Company (f/k/a Western	ER96-858
20	Massachusetts Electric Company) Rate Schedule	
21	FERC No. 405 (New England Power Company)	
22		
23	NSTAR Electric Company, Rate Schedule	ER18-749
24	FERC No. 407 (Massachusetts Municipal Wholesale	
25	Electric Company – Stony Brook – Ludlow Agreement)	
26		
27	NSTAR Electric Company,	ER17-1335, ER18-749
28	Service Agreement No. IA-ES-38,	
29	(Nautilus Hydro, LLC - Dwight Hydro Generator IA)	
30		
31	NSTAR Electric Company,	ER17-1336, ER18-749
32	Service Agreement No. IA-ES-39,	
33	(Nautilus Hydro, LLC - Gardner Fall Generator IA)	
34		
35	NSTAR Electric Company,	ER17-1338, ER18-749
36	Service Agreement No. IA-ES-40,	
37	(Nautilus Hydro, LLC - Indian Orchard Generator I)	
38		
39	NSTAR Electric Company,	ER17-1339, ER18-749
40	Service Agreement No. IA-ES-41,	
41	(Nautilus Hydro, LLC - Putts Bridge Generator IA)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INFORMATION ON FORMULA RATES (continued)

FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	[X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	NSTAR Electric Company,	ER17-1340, ER18-749
2	Service Agreement No. IA-ES-42,	
3	(Nautilus Hydro, LLC - Red Bridge Generator IA)	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	[X] Yes [ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20170728-5230	07/28/2017	RT04-2-000	Annual New England Participating	ISO New England Inc. Transmission
2		07/28/2017	ER09-1532-000	Transmission Owners Administrative	Markets and Services Tariff
3				Regional Network Service	Attachment F
4				Information Filing	
5					
6	20180531-5427	05/31/2018	ER09-1243-000	Annual Informational Filing	ISO New England Inc. Transmission
7		05/31/2018	ER07-549-000	of NSTAR Electric Company	Markets and Services Tariff, Section II,
8					Schedule 21-NSTAR
9					
10	20180629-5315	06/29/2018	ER09-1243-000	Annual Informational Filing	ISO New England Inc. Transmission
11	20180629-5316	06/29/2018	ER07-549-000	CWIP Supplement of NSTAR	Markets and Services Tariff, Section II,
12				Electric Company	Schedule 21-NSTAR
13					
14	20180731-5221	07/31/2018	RT04-2-000	Annual New England Participating	ISO New England Inc. Transmission
15		07/31/2018	ER09-1532-000	Transmission Owners Administrative	Markets and Services Tariff
16				Regional Network Service	Attachment F
17				Information Filing	
18					
19	20180917-5054	09/17/2018	RT04-2-000	Supplement to July 31, 2018	ISO New England Inc. Transmission
20		09/17/2018	ER09-1532-000	Annual New England Participating	Markets and Services Tariff
21				Transmission Owners Administrative	Attachment F
22				Regional Network Service	
23				Information Filing	
24					
25					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1	110-111	Comp Balance Sheet (Assets and Other Debt)	c	3
2	112-113	Comp Balance Sheet (Liabilities and Other Credits)	c,d	2,3,16,18,21
3	200-201	Summary of Utility Plant & Accumulated Provisions	c	21
4	204-207	Electric Plant In Service (Acct 101 - 103 and 106)	g	5,100
5	204-207	Electric Plant In Service (Acct 101 - 103 and 106)	b,g	9,13,49,50,58,61,62,66
6				67,75,99,104
7	219	Accum Provision for Depr of Electric (Account 108)	b	19,25,26,28
8	234	Accumulated Deferred Income Taxes	b,c	18
9	234	Accumulated Deferred Income Taxes	c	2
10	262-263	Taxes Accrued, Prepaid and Charged During Year	i	29,32
11	275	Accum Deferred Income Taxes-Property (Acct. 282)	k	9
12	277	Accuum Deferred Income Taxes-Other (Acct 283)	k	19
13	278	Other Regulatory Liabilities (Account 254)	f	3
14	300	Electric Operating Revenues (Account 400)	b	21,22
15	320-323	Electric Operation and Maintenance Expenses	b	112
16	320-323	Electric Operation and Maintenance Expenses	b,c	98,198
17	336	Deprec. & Amort. Of electric Plant (403, 404, 405)	b	7,8,10
18	400	Monthly Transmission System Peak Load	b	1-17
19	401b	Monthly Peaks and Output	d	29-40
20				
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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. None

2. None

3. None

4. None

5. None

6. During 2018, the Company did not assume any obligations as a guarantor of another's performance.

   The amount of short-term borrowings that may be incurred by NSTAR Electric is subject to periodic approval by the FERC. On November 30, 2017, the FERC granted authorization to allow NSTAR Electric to issue total short-term debt securities in an aggregate principal amount not to exceed $655 million outstanding at any one-time, effective December 31, 2017 through December 30, 2019.

   NSTAR Electric is a party to a five-year $650 million revolving credit facility. The revolving credit facility's termination date is December 8, 2023. The revolving credit facility serves to backstop NSTAR Electric's $650 million commercial paper program. As of December 31, 2018, NSTAR Electric had no borrowings outstanding under this facility.

   As of December 31, 2018, NSTAR Electric had approximately $278.5 million in borrowings outstanding under its commercial paper program.

7. None

8. Estimated Annual Effect and Nature of Important Wage Scale Changes

Company	Group	Effective Date	2018 Number of Employees	General Wage Increase Percent	Estimated Annualized Cost of Increase
NSTAR	USWA 12004	03/31/18	254	2.75%	$ 679,600
NSTAR	UWUA 369	06/01/18	1,692	3.00%	$ 4,678,857
Western Mass Electric	IBEW (Physical and Technical)	10/01/18	221	3.00%	$ 539,134

9. For a discussion of materially important legal proceedings, see Page 123, Notes to Financial Statements, Note 12, Commitments and Contingencies.

10. None

11. (Reserved)

12. N/A

13. Changes in the officers and directors of the respondent during the period have been reported on pages 104 and 105 and the corresponding footnotes thereto.

There were no changes in the major security holders and voting powers during the period.

14. NSTAR Electric Company proprietary capital ratio is greater than 30%.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	*(Mo, Da, Yr)* / /	End of 2018/Q4

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	10,932,014,320	10,301,966,288
3	Construction Work in Progress (107)	200-201	470,314,379	447,851,109
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		11,402,328,699	10,749,817,397
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,967,931,831	2,802,914,195
6	Net Utility Plant (Enter Total of line 4 less 5)		8,434,396,868	7,946,903,202
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)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		8,434,396,868	7,946,903,202
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		4,858,250	5,030,847
19	(Less) Accum. Prov. for Depr. and Amort. (122)		94,887	92,740
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	16,024,653	6,791,505
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)		901,590	1,008,883
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		132,809,645	126,948,028
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)		154,499,251	139,686,523
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		0	0
36	Special Deposits (132-134)		13,054,421	12,917,853
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		299,302,350	279,632,436
41	Other Accounts Receivable (143)		134,848,169	125,933,178
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		74,411,265	69,561,390
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		32,582,097	41,403,616
45	Fuel Stock (151)	227	0	0
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	61,693,671	49,531,530
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	65,594,115	50,391,921

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	*(Mo, Da, Yr)* / /	End of 2018/Q4

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	45,571	391,487
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)		41,020,772	11,963,323
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		107,588	73,730
60	Rents Receivable (172)		1,449,638	5,195,312
61	Accrued Utility Revenues (173)		34,517,648	49,864,790
62	Miscellaneous Current and Accrued Assets (174)		0	0
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)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		609,804,775	557,737,786
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		17,645,331	19,455,830
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	1,428,335,359	1,504,849,772
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,267,208	373,635
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)		303	-92,034
77	Temporary Facilities (185)		-522,765	-1,270,673
78	Miscellaneous Deferred Debits (186)	233	90,022,171	76,809,391
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)		10,638,072	11,319,222
82	Accumulated Deferred Income Taxes (190)	234	462,181,372	398,218,961
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,010,567,051	2,009,664,104
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		11,209,267,945	10,653,991,615

Schedule Page: 110 Line No.: 2 Column: c

In the third quarter of 2018, management identified and corrected a $1.1 million error related to retirements that resulted in a misclassification as of December 31, 2017 between accounts 101 and 108.

Schedule Page: 110 Line No.: 3 Column: c

WEST:
Information on Formula Rates:
Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Schedule Page: 110 Line No.: 52 Column: c

Represents the value of Renewable Energy Certificates (RECs) that NSTAR Electric Company uses to meet the Commonwealth of Massachusetts' Renewable Portfolio Standards requirements. These RECs are recorded in Account 158.3.

Schedule Page: 110 Line No.: 52 Column: d

Represents the value of Renewable Energy Certificates (RECs) that NSTAR Electric Company uses to meet the Commonwealth of Massachusetts' Renewable Portfolio Standards requirements. These RECs are recorded in Account 158.3.

Schedule Page: 110 Line No.: 57 Column: c

At December 31, 2018, the total Prepayments balance in Account 165 includes NSTAR Electric East related prepayments of the following amounts:

Prepaid State Taxes	$ 6,309,081	dr.
Prepaid Insurance	1,824,792	dr.
Prepaid Interest	89,097	dr.
Prepaid Lease	80,133	dr.
Prepaid Workers Comp.	638,600	dr.
Prepaid Agency Fees	518,788	dr.
Prepaid Postage	33,600	dr.
Prepaid Federal Taxes	26,592,632	dr.
Prepaid Other	28,628	dr.
	$ 36,115,352	dr.

At December 31, 2018, the total Prepayments balance in Account 165 includes NSTAR Electric West related prepayments of the following amounts:

Prepaid State Taxes	1,415,621	dr.
Prepaid Insurance	374,546	dr.
Prepaid Lease	70,874	dr.
Prepaid Workers Comp.	212,060	dr.
Prepaid Software License Maint.	62,220	dr.
Prepaid Vehicle Property Taxes	45,256	dr.
Prepaid Vehicle Costs	92,736	dr.
Prepaid Federal Taxes	2,625,382	dr.
Prepaid Other	6,725	dr.
	$ 4,905,420	dr.

At December 31, 2018, the total Prepayments balance in Account 165 includes NSTAR Electric West transmission related prepayments of the following amounts:

Prepaid State Taxes	$	1,524,190	dr.
Prepaid Federal Taxes		(7,932,969)	cr.
Prepaid Insurance		157,140	dr.
Prepaid Lease		(500)	cr.
Prepaid Software License Maint.		15,555	dr.
Prepaid Other		5,516	dr.
Total	$	(6,231,068)	cr.

Schedule Page: 110 Line No.: 69 Column: c

At December 31, 2018, the total Unamortized Debt Expenses balance in Account 181 includes NSTAR Electric East related Debt of the following amounts:

Debentures Due 03/2044	$	2,571,563	dr.
Debentures Due 03/2036		1,252,508	dr.
Debentures Due 03/2040		2,214,080	dr.
Debentures Due 10/2022		1,208,859	dr.
Debentures Due 11/2025		1,467,011	dr.
Debentures Due 06/2026		1,581,921	dr.
Debentures Due 05/2027		5,421,260	dr.
DPU Financing Plan		120,600	dr.
Total	$	15,837,802	dr.

At December 31, 2018, the total Unamortized Debt Expenses balance in Account 181 includes NSTAR Electric West related Debt of the following amounts:

Series E. Due 03/2020	$	115,801	dr.
Series G. Due 11/2023		220,279	dr.
Series H. Due 06/2026		230,720	dr.
Series F. Due 09/2021		642,725	dr.
Series D. Due 08/2037		311,081	dr.
Series B. Due 09/2034		286,923	dr.
	$	1,807,529	dr.

Schedule Page: 110 Line No.: 72 Column: c

For Form 1 reporting purposes, the following reclassification of debit or credit balance accounts at December 31, 2018 are being included with Account 182.3 - Other Regulatory Assets. The balances are as follows:

Balance in Account 182.3	1,221,308,267	dr.
Reclass of balances to Account 254: Mitigation Incentive Timing - DPU 05-89	314,352	dr.
Reclass of balances to Account 254: Pension and PBOP	33,542,425	dr.
Reclass of balances from Account 254: Basic Service Adder True up	124,429	cr.

Reclass of balances from Account 254: Deferred Transition Rev BECO	639,186	cr.
Reclass of balances to Account 254: Deferred Basic Service	4,518,390	dr.
Reclass of balances to Account 254: Deferred Transmission Revenues	88,984,023	dr.
Reclass of balances from Account 254: Deferred NSTAR Green	128,418	cr.
Reclass of balances to Account 254: Reg Asset Revenue Decoupling	717,159	dr.
Reclass of balances to Account 254: Deferred DSM Revenue	66,942,442	dr.
Reclass of balances to Account 254: Deferred Metering Costs	12,735,130	dr.
Reclass of balances to Account 254: Uncollectibles Assoc with Basic Service	181,536	dr.
Reclass of balances from Account 254: Protective Hardship Credit	16,332	cr.
Account 182.3 Being Reported	1,428,335,359	dr.

Schedule Page: 110 Line No.: 72 Column: d

For Form 1 reporting purposes, the following reclassification of debit or credit balance accounts at December 31, 2017 are being included with Account 182.3 - Other Regulatory Assets. The balances are as follows:

Balance in Account 182.3	$	1,309,814,848	dr.
Reclass of balances from Account 254: Deferred Energy Efficiency		134,250,783	dr.
Reclass of balances to Account 254: Transition Reconciliation		5,730,439	dr.
Reclass of balances from Account 254: Basic Service Uncollectibles		21,513	cr.
Reclass of balances to Account 254: Deferred Transmission Revenues		14,941,252	dr.
Reclass of balances to Account 254: Pension and PBOP		40,133,963	dr.
Account 182.3 Being Reported	$	1,504,849,772	dr.

Schedule Page: 110 Line No.: 81 Column: c

Ferc Account	Company	Ending Balance
189	East Distribution	10,439,401
	West Distribution	66,224
	West Transmission	132,447
189 Total		**10,638,072**

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2018/Q4

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	200	200
3	Preferred Stock Issued (204)	250-251	43,000,000	43,000,000
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		3,905,151	3,905,151
7	Other Paid-In Capital (208-211)	253	2,814,604,083	2,684,104,083
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	924,875,880	767,478,875
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-11,851,691	-7,584,838
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)	-1,378,596	-1,824,103
16	Total Proprietary Capital (lines 2 through 15)		3,773,155,027	3,489,079,368
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
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	2,965,000,000	2,965,000,000
22	Unamortized Premium on Long-Term Debt (225)		6,432,505	7,934,344
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		8,941,217	9,719,241
24	Total Long-Term Debt (lines 18 through 23)		2,962,491,288	2,963,215,103
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		3,442,730	3,754,457
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		45,644,076	37,562,761
29	Accumulated Provision for Pensions and Benefits (228.3)		19,113,908	94,156,648
30	Accumulated Miscellaneous Operating Provisions (228.4)		7,247,160	2,701,959
31	Accumulated Provision for Rate Refunds (229)		2,977,239	2,977,239
32	Long-Term Portion of Derivative Instrument Liabilities		0	176,612
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		63,400,062	44,574,835
35	Total Other Noncurrent Liabilities (lines 26 through 34)		141,825,175	185,904,511
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		278,500,000	234,000,000
38	Accounts Payable (232)		369,724,650	329,786,653
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		85,933,152	91,791,910
41	Customer Deposits (235)		8,002,577	8,195,387
42	Taxes Accrued (236)	262-263	5,889,025	12,127,449
43	Interest Accrued (237)		25,526,493	25,515,271
44	Dividends Declared (238)		489,998	489,998
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
NSTAR Electric Company	(1) [x] An Original (2) [ ] A Resubmission	*(mo, da, yr)* / /	end of 2018/Q4

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)		3,892,582	3,875,632
48	Miscellaneous Current and Accrued Liabilities (242)		278,161,382	228,387,970
49	Obligations Under Capital Leases-Current (243)		310,693	319,752
50	Derivative Instrument Liabilities (244)		123,106	1,232,421
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	176,611
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,056,553,658	935,545,832
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		47,196,139	52,386,151
57	Accumulated Deferred Investment Tax Credits (255)	266-267	31,935,098	10,671,434
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	52,778,123	42,391,952
60	Other Regulatory Liabilities (254)	278	1,374,279,273	1,296,363,587
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)		1,261,473,709	1,191,923,425
64	Accum. Deferred Income Taxes-Other (283)		507,580,455	486,510,252
65	Total Deferred Credits (lines 56 through 64)		3,275,242,797	3,080,246,801
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		11,209,267,945	10,653,991,615

Schedule Page: 112 Line No.: 2 Column: c

Information on Formula Rates:

EAST:

Page 106.2 line 1 Amount stipulated per contract.

Schedule Page: 112 Line No.: 2 Column: d

Information on Formula Rates:

EAST:

Page 106.2 line 1 Amount stipulated per contract.

Schedule Page: 112 Line No.: 3 Column: c

	Total	East	West
Total of Preferred Stock	43,000,000	43,000,000	0

EAST:

Page 106 lines 16, 19 Amount stipulated per contract.

Page 106.2 lines 1, 5 Amount stipulated per contract

Schedule Page: 112 Line No.: 3 Column: d

Information on Formula Rates:

EAST:

Page 106 lines 16, 19 Amount stipulated per contract.

Page 106.2 lines 1, 5 Amount stipulated per contract

Schedule Page: 112 Line No.: 16 Column: c

	Total	East	West
Total Proprietary Capital	3,773,155,027	3,053,220,505	719,934,522

Information on Formula Rates:

EAST:

Page 106.2 lines 1, 5 Amount stipulated per contract.

Schedule Page: 112 Line No.: 16 Column: d

Information on Formula Rates:

EAST:

Page 106.2 lines 1, 5 Amount stipulated per contract.

Schedule Page: 112 Line No.: 18 Column: c

Information on Formula Rates:

Page 106.2 lines 1, 5 Amount stipulated per contract.

Schedule Page: 112 Line No.: 18 Column: d

Information on Formula Rates:

Page 106.2 lines 1, 5 Amount stipulated per contract.

Schedule Page: 112 Line No.: 21 Column: c

Information on Formula Rates:

EAST:

Page 106 lines 16, 19 Amount stipulated per contract.

Page 106.2 lines 1, 5 Amount stipulated per contract.

Schedule Page: 112 Line No.: 21 Column: d

Information on Formula Rates:

EAST:

Page 106 lines 16, 19 Amount stipulated per contract.

Page 106.2 lines 1, 5 Amount stipulated per contract.

Schedule Page: 112 Line No.: 22 Column: c

	Total	East	West
Total Unamortized Premium on Long-Term Debt	6,432,505	3,570,000	2,862,505

Schedule Page: 112 Line No.: 23 Column: c

	Total	East	West
Total of Unamortized Discount on Long-Term Debt	8,941,217	8,451,562	489,655

Schedule Page: 112 Line No.: 24 Column: c

	Total	East	West
Total of Long-Term Debt	2,962,491,288	2,395,118,438	567,372,850

Schedule Page: 112 Line No.: 60 Column: c

For Form 1 reporting purposes, the following reclassification of debit or credit balance accounts at December 31, 2018 are being included with Account 254 - Other Regulatory Liabilities. The balances are as follows:

Balance in Account 254	1,167,252,181	cr.
Reclass of balances from Account 182.3: Mitigation Incentive Timing - DPU 05-89	314,352	cr.
Reclass of balances from Account 182.3: Pension and PBOP	33,542,425	cr.
Reclass of balances to Account 182.3: Basic Service Adder True up	124,429	dr.
Reclass of balances to Account 182.3: Deferred Transition Rev BECO	639,186	dr.
Reclass of balances from Account 182.3: Deferred Basic Service	4,518,390	cr.
Reclass of balances from Account 182.3: Deferred Transmission Revenues	88,984,023	cr.
Reclass of balances to Account 182.3: Deferred NSTAR Green	128,418	dr.

Reclass of balances from Account 182.3: Reg Asset Revenue Decoupling	717,159	cr.
Reclass of balances from Account 182.3: Deferred DSM Revenue	66,942,442	cr.
Reclass of balances from Account 182.3: Deferred Metering Costs	12,735,130	cr.
Reclass of balances from Account 182.3: Uncollectibles Assoc with Basic Service	181,536	cr.
Reclass of balances to Account 182.3: Protective Hardship Credit	16,332	dr.
Account 254 Being Reported	1,374,279,273	cr.

Schedule Page: 112 Line No.: 60 Column: d

For Form 1 reporting purposes, the following reclassification of debit or credit balance accounts at December 31, 2017 are being included with Account 254 - Other Regulatory Liabilities. The balances are as follows:

Balance in Account 254	1,101,328,663	cr.
Reclass of balances to Account 182.3: Deferred Energy Efficiency	134,250,783	cr.
Reclass of balances from Account 182.3: Transition Reconciliation	5,730,439	cr.
Reclass of balances to Account 182.3: Basic Service Uncollectibles	21,513	dr.
Reclass of balances from Account 182.3: Deferred Transmission Revenues	14,941,252	cr.
Reclass of balances from Account 182.3: Pension and PBOP	40,133,963	cr.
Account 254 Being Reported	1,296,363,587	cr.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	3,359,868,073	3,212,553,594		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,123,315,455	1,924,731,430		
5	Maintenance Expenses (402)	320-323	97,135,001	87,747,982		
6	Depreciation Expense (403)	336-337	268,623,877	265,031,848		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	4,730,484	7,357,498		
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)		47,943,523	34,883,593		
13	(Less) Regulatory Credits (407.4)		-14,398,286	-2,096,422		
14	Taxes Other Than Income Taxes (408.1)	262-263	193,925,747	181,647,591		
15	Income Taxes - Federal (409.1)	262-263	76,519,265	111,203,256		
16	- Other (409.1)	262-263	28,549,669	26,226,916		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	180,177,048	181,008,936		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	141,611,239	72,997,470		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,789,183	-1,766,023		
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)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,891,917,933	2,747,171,979		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		467,950,140	465,381,615		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
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)	
						1
3,359,868,073	3,212,553,594					2
						3
2,123,315,455	1,924,731,430					4
97,135,001	87,747,982					5
268,623,877	265,031,848					6
						7
4,730,484	7,357,498					8
						9
						10
						11
47,943,523	34,883,593					12
-14,398,286	-2,096,422					13
193,925,747	181,647,591					14
76,519,265	111,203,256					15
28,549,669	26,226,916					16
180,177,048	181,008,936					17
141,611,239	72,997,470					18
-1,789,183	-1,766,023					19
						20
						21
						22
						23
						24
2,891,917,933	2,747,171,979					25
467,950,140	465,381,615					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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)		467,950,140	465,381,615		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		848,031	1,036,862		
34	(Less) Expenses of Nonutility Operations (417.1)		595,041	674,950		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-4,266,853	-9,327,855		
37	Interest and Dividend Income (419)		803,850	1,850,186		
38	Allowance for Other Funds Used During Construction (419.1)		15,117,148	10,175,401		
39	Miscellaneous Nonoperating Income (421)		17,869,524	19,546,935		
40	Gain on Disposition of Property (421.1)		547,851	105,077		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		30,324,510	22,711,656		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		389,847	489,566		
46	Life Insurance (426.2)		-210,150	-3,243,667		
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		644,481	731,277		
49	Other Deductions (426.5)		1,004,473	4,426,646		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,828,651	2,403,822		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	336,731	311,528		
53	Income Taxes-Federal (409.2)	262-263	-1,747,842	-1,512,200		
54	Income Taxes-Other (409.2)	262-263	-407,937	-83,848		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	9,676,153	6,609,744		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	84,921	130,457		
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)		7,772,184	5,194,767		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		20,723,675	15,113,067		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		111,682,568	118,552,013		
63	Amort. of Debt Disc. and Expense (428)		3,617,567	3,656,868		
64	Amortization of Loss on Reaquired Debt (428.1)		681,150	681,150		
65	(Less) Amort. of Premium on Debt-Credit (429)		1,501,839	1,631,504		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)			817,168		
68	Other Interest Expense (431)		-1,598,931	-11,528,597		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		7,296,852	4,778,393		
70	Net Interest Charges (Total of lines 62 thru 69)		105,583,663	105,768,705		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		383,090,152	374,725,977		
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)		383,090,152	374,725,977		

Schedule Page: 114 Line No.: 13 Column: c

Ferc Account	Company	Ending Balance
407.4	NSTAR Electric East	$ 335,421
	West	(14,733,707)
407.4 Total		**$ (14,398,286)**

Schedule Page: 114 Line No.: 19 Column: c

Ferc Account	Company	Ending Balance
411.4	NSTAR Electric East	$ (1,151,351)
	West	(637,832)
411.4 Total		**$ (1,789,183)**

Schedule Page: 114 Line No.: 38 Column: c

Ferc Account	Company	Ending Balance
419.1	NSTAR Electric East	$ 14,920,641
	West	196,507
419.1 Total		**$ 15,117,148**

Schedule Page: 114 Line No.: 49 Column: c

Note that for the year ended December 31, 2018, the total amount of Public Education expenses in Account 426.5 includes a transmission related component of $0.

Schedule Page: 114 Line No.: 63 Column: c

Ferc Account	Company	Ending Balance
428	NSTAR Electric East	$ 2,313,452
	West	1,304,115
428 Total		**$ 3,617,567**

Schedule Page: 114 Line No.: 64 Column: c

Ferc Account	Company	Ending Balance
428.1	NSTAR Electric East	$ 606,648
	West Distribution	24,834
	West Transmission	49,668
428.1 Total		**$ 681,150**

FOOTNOTE DATA

Schedule Page: 114 Line No.: 65 Column: c

Ferc Account	Company	Ending Balance
429	NSTAR Electric East	$ 428,400
	West	1,073,439
429 Total		**$ 1,501,839**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		767,478,875	657,385,043
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11	Adjustment undistributed Retained Earnings			
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		387,357,005	384,053,832
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	4.25% Cumulative Preferred Stock		-765,000	(765,000)
25	4.78% Cumulative Preferred Stock		-1,195,000	(1,195,000)
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-1,960,000	(1,960,000)
30	Dividends Declared-Common Stock (Account 438)			
31	200 Shares Outstanding (Dividend to Parent Company)		-228,000,000	(272,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-228,000,000	(272,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		924,875,880	767,478,875
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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)
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)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		924,875,880	767,478,875
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-7,584,838	1,743,016
50	Equity in Earnings for Year (Credit) (Account 418.1)		-4,266,853	(9,327,855)
51	(Less) Dividends Received (Debit)			
52	Transfer to Acct 216			
53	Balance-End of Year (Total lines 49 thru 52)		-11,851,691	(7,584,839)

FOOTNOTE DATA

Schedule Page: 118 Line No.: 29 Column: c

All preferred stock is related to NSTAR Electric East.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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)	383,090,152	374,725,977
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	273,354,361	272,389,346
5	Amortization of Debt Discount and Expense	2,796,878	2,706,514
6	Uncollectible Expense	22,279,299	21,251,537
7	Amortization of Regulatory Assets, Net	62,341,809	36,980,015
8	Deferred Income Taxes (Net)	48,157,041	114,490,753
9	Investment Tax Credit Adjustment (Net)	-1,789,183	-1,766,023
10	Net (Increase) Decrease in Receivables	-27,028,926	-30,092,973
11	Net (Increase) Decrease in Inventory	-11,816,225	-5,243,946
12	Net (Increase) Decrease in Allowances Inventory	-15,202,195	-19,197,339
13	Net Increase (Decrease) in Payables and Accrued Expenses	49,350,605	27,072,289
14	Net (Increase) Decrease in Other Regulatory Assets	54,066,435	18,861,447
15	Net Increase (Decrease) in Other Regulatory Liabilities	65,923,518	-57,854,800
16	(Less) Allowance for Other Funds Used During Construction	15,117,148	10,175,401
17	(Less) Undistributed Earnings from Subsidiary Companies	-4,266,853	-9,327,855
18	Other (provide details in footnote):		
19	Pension and PBOP contributions	-61,751,473	-90,720,640
20	Pension and PBOP Income, Net	-21,697,389	-9,886,418
21	Other, Net	-29,413,207	-14,896,656
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	781,811,205	637,971,537
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-728,525,770	-725,338,830
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-15,117,148	-10,175,401
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-713,408,622	-715,163,429
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	-13,500,000	-2,300,000
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)	-1,282,485	-3,868,512
45	Proceeds from Sales of Investment Securities (a)	1,340,790	3,934,036

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	Other Investments, Net		-1,087
55	Contribution to Equity Method Investment		-3,616,775
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-726,850,317	-721,015,767
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		700,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Capital Contribution from Parent	130,500,000	2,300,000
66	Net Increase in Short-Term Debt (c)	44,500,000	107,500,000
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	175,000,000	809,800,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-400,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Financing Expenses, Net	107,614	-1,795,770
78	Net Decrease in Short-Term Debt (c)		
79	Notes Payable to Associated Companies		-51,000,000
80	Dividends on Preferred Stock	-1,960,000	-1,960,000
81	Dividends on Common Stock	-228,000,000	-272,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-54,852,386	83,044,230
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	108,502	
87			
88	Cash and Cash Equivalents at Beginning of Period	12,944,531	
89			
90	Cash and Cash Equivalents at End of period	13,053,033	

FOOTNOTE DATA

Schedule Page: 120 Line No.: 88 Column: b

FERC PAGE NUMBER	LINE #	TITLE OF ACCOUNT	BALANCE
110	35	Cash (131)	$ -
		Restricted Cash	12,944,531
		Total	$ 12,944,531

See Notes to Financial Statements, Footnotes 1C and 1P.

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

FERC PAGE NUMBER	LINE #	TITLE OF ACCOUNT	BALANCE
110	35	Cash (131)	$ -
		Restricted Cash	13,053,033
		Total	$ 13,053,033

See Notes to Financial Statements, Footnotes 1C and 1P.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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 Commmission 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.

On December 31, 2017, affiliate Western Massachusetts Electric Company, was merged into NSTAR Electric Company. This report reflects the combined company. Additional detail by legacy company is provided in footnotes as needed.

The financial statements have been prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than GAAP. NSTAR Electric's Combined Notes to Financial Statements relate to all of Eversource Energy's subsidiaries, including CL&P and PSNH, and are prepared in conformity with GAAP. Accordingly, certain footnotes are not reflective of NSTAR Electric's financial statements contained herein. Refer to the Glossary of Terms for abbreviations and acronyms used throughout the Combined Notes to Financial Statements. The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

Investments in subsidiaries are unconsolidated and are reported on the equity basis in FERC account 123.1 on page 110 in the FERC Form 1 in accordance with the Uniform System of Accounts prescribed by the FERC. Other general purpose financial statements are prepared on a consolidated basis in accordance with GAAP.

Certain regulatory assets and liabilities are reported on a gross basis in FERC accounts 182 and 254 on pages 111 and 113 in the FERC Form 1 and are reported on a net basis and separated into their current and long-term portions in other general purpose financial statements prepared in accordance with GAAP.

Certain amounts recorded as materials and supplies in FERC account 154 are reported in aggregate as a current asset on page 110 in the FERC Form 1 and are separated into their current and long-term portions in other general purpose financial statements prepared in accordance with GAAP.

Unamortized debt expenses recorded in FERC account 181 are reported as a long-term asset on page 111 in the FERC Form 1 and are reported as a direct deduction from the carrying amount of long-term debt in other general purpose financial statements prepared in accordance with GAAP.

Certain miscellaneous assets and liabilities in FERC accounts 186, 229 and 242 on pages 111, 112 and 113 in the FERC Form 1 are reported as regulatory assets or liabilities in other general purpose financial statements prepared in accordance with GAAP.

Cost of removal obligations are included in the accumulated provision for depreciation in FERC account 108 on page 110 in the FERC Form 1 and are reported as a regulatory liability in other general purpose financial statements prepared in accordance with GAAP.

Accumulated deferred income taxes are reported on a gross basis in FERC accounts 190, 282 and 283 on pages 111 and 113 in the FERC Form 1 and are reported on a net basis in other general purpose financial statements prepared in accordance with GAAP.

Taxes receivable and payable are reported on a gross basis in FERC accounts 143 and 236 on pages 110 and 112 in the FERC Form 1 and tax prepayments are reported in FERC account 165 on page 111 in the FERC Form 1. These amounts are shown on a net basis by taxing jurisdiction as a current asset or liability in other general purpose financial statements prepared in accordance with GAAP.

Long-term debt is reported in aggregate in the FERC Form 1 and is segregated between current and long-term in other general purpose financial statements prepared in accordance with GAAP.

Proprietary capital is reported per final filed accounting entries of NSTAR Electric Company related to the merger of Eversource Energy (formerly Northeast Utilities) and NSTAR under AC13-4 et al. Docket No. EC11-35 in FERC accounts 207, 211, 214, and 216 on pages 112 and 118 in the FERC Form 1 and is not reclassed in other general purpose financial statements prepared in accordance with GAAP.

Certain revenue and expense items are reported on a gross basis in FERC accounts 400, 401, 403, 407, 409, 410 and 411 on pages 114 and 117 in the FERC Form 1 and are reported on a net basis in other general purpose financial statements prepared in accordance with GAAP.

Certain items that are recorded in other income and deductions in FERC accounts 408.2, 417, 419, 421 and 426 and in interest expense in FERC account 431 on page 117 in the FERC Form 1 are reported in operating revenues or operating expenses in other general purpose financial statements prepared in accordance with GAAP.

The nonservice components of pension, SERP and PBOP costs are reported in FERC account 926 within Operating Expenses on page 114 in the FERC Form 1 and are presented as non-operating income/(loss) in other general purpose financial statements prepared in accordance with GAAP. The capitalized portion of these nonservice components are recorded within Utility Plant on page 110 in the FERC Form 1 and are reported as a regulatory asset or liability in other general purpose financial statements prepared in accordance with GAAP.

The impact of revenue decoupling, which is the difference between allowed base distribution revenue and actual revenue collected from customers, is reported in FERC account 407 on page 114 in the FERC Form 1 and is reported in operating revenues in other general purpose financial statements prepared in accordance with GAAP.

GAAP requires that public entities report certain information about operating segments in complete sets of financial statements of the entity and certain information about their products and services. GAAP requires disclosure of a measure of segment profit or loss, certain specific revenue and expense items, and segment assets along with reconciliations of amounts disclosed for segments to corresponding amounts in the entity's general purpose financial statements. These disclosures are not required for FERC reporting purposes.

NSTAR Electric has evaluated events subsequent to December 31, 2018 through the issuance of the GAAP financial statements on February 26, 2019, and has updated such evaluation for disclosure purposes through April 16, 2019 and did not identify any such events that required disclosure under this guidance.

See "Index to the Combined Notes to Financial Statements" for a listing of applicable notes for NSTAR Electric.

Index to the Combined Notes to Financial Statements
The notes to the financial statements that follow are a combined presentation. The following list indicates the registrants to which the footnotes apply:

Registrant	Applicable Notes
The Connecticut Light and Power Company	1 (A - C, E – K, M - Q), 2, 3, 4, 6, 7, 8, 9, 10 (A – D), 11, 12 (A – E, G), 14, 15, 16, 17, 18, 19, 22, 25
NSTAR Electric Company	1 (A - C, E, F, H, I, K, M, N, P, Q), 2, 3, 6, 7, 8, 9, 10 (A – D), 11, 12 (A – G), 14, 15, 16, 17, 18, 19, 22, 25
Public Service Company of New Hampshire	1 (A - C, E, F, H, I, K – N, P, Q), 2, 3, 6, 7, 8, 9, 10 (A – D), 11, 12 (A – E, G), 13, 14, 15, 16, 17, 18, 22, 25

EVERSOURCE ENERGY AND SUBSIDIARIES
THE CONNECTICUT LIGHT AND POWER COMPANY
NSTAR ELECTRIC COMPANY AND SUBSIDIARY
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE AND SUBSIDIARIES

COMBINED NOTES TO FINANCIAL STATEMENTS

Refer to the Glossary of Terms included in this combined Annual Report on Form 10-K for abbreviations and acronyms used throughout the combined notes to the financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A. About Eversource, CL&P, NSTAR Electric and PSNH

Eversource Energy is a public utility holding company primarily engaged, through its wholly-owned regulated utility subsidiaries, in the energy delivery business. Eversource Energy's wholly-owned regulated utility subsidiaries consist of CL&P, NSTAR Electric and PSNH (electric utilities), Yankee Gas and NSTAR Gas (natural gas utilities) and Aquarion (water utilities). Eversource provides energy delivery and/or water service to approximately four million electric, natural gas and water customers through eight regulated utilities in Connecticut, Massachusetts and New Hampshire.

Eversource, CL&P, NSTAR Electric and PSNH are reporting companies under the Securities Exchange Act of 1934. Eversource Energy is a public utility holding company under the Public Utility Holding Company Act of 2005. Arrangements among the regulated electric companies and other Eversource companies, outside agencies and other utilities covering interconnections, interchange of electric power and sales of utility property are subject to regulation by the FERC. Eversource's regulated companies are subject to regulation of rates, accounting and other matters by the FERC and/or applicable state regulatory commissions (the PURA for CL&P, Yankee Gas and Aquarion, the DPU for NSTAR Electric, NSTAR Gas and Aquarion, and the NHPUC for PSNH and Aquarion).

CL&P, NSTAR Electric and PSNH furnish franchised retail electric service in Connecticut, Massachusetts and New Hampshire. Yankee Gas and NSTAR Gas are engaged in the distribution and sale of natural gas to customers within Connecticut and Massachusetts, respectively. Aquarion is engaged in the collection, treatment and distribution of water in Connecticut, Massachusetts and New Hampshire. CL&P, NSTAR Electric and PSNH's results include the operations of their respective distribution and transmission businesses. The distribution business also includes the results of NSTAR Electric's solar power facilities and PSNH's generation facilities prior to sale in 2018. PSNH completed the sales of its thermal generation assets on January 10, 2018 and its hydroelectric generation assets on August 26, 2018. As of December 31, 2018, PSNH does not own any electric generation facilities. See Note 13, "Generation Asset Sale," for further information.

Eversource also has a regulated subsidiary, NPT, which was formed to construct, own and operate the Northern Pass line, a HVDC transmission line from Québec to New Hampshire under development that will interconnect with a new HVDC transmission line being developed by a transmission subsidiary of HQ.

Eversource Service, Eversource's service company, and several wholly-owned real estate subsidiaries of Eversource, provide support services to Eversource, including its regulated companies. Eversource holds several equity ownership interests, which are accounted for under the equity method. Eversource also consolidates the operations of CYAPC and YAEC, both of which are inactive regional nuclear generation companies engaged in the long-term storage of their spent nuclear fuel.

B. Basis of Presentation

The consolidated financial statements of Eversource, NSTAR Electric and PSNH include the accounts of each of their respective subsidiaries. Intercompany transactions have been eliminated in consolidation. The accompanying consolidated financial statements of Eversource, NSTAR Electric and PSNH and the financial statements of CL&P are herein collectively referred to as the "financial statements."

The preparation of the 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 liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Eversource consolidates CYAPC and YAEC because CL&P's, NSTAR Electric's and PSNH's combined ownership and voting interests in each of these entities is greater than 50 percent. Intercompany transactions between CL&P, NSTAR Electric, PSNH and the CYAPC and YAEC companies have been eliminated in consolidation of the Eversource financial statements.

Eversource's utility subsidiaries' electric, natural gas and water distribution and transmission businesses, are subject to rate-regulation that is based on cost recovery and meets the criteria for application of accounting guidance for entities with rate-regulated operations, which considers the effect of regulation on the differences in the timing of the recognition of certain revenues and expenses from those of other businesses and industries. See Note 2, "Regulatory Accounting," for further information.

Eversource's consolidated financial information includes the results of Aquarion and its subsidiaries beginning from the date of the acquisition on December 4, 2017.

Certain reclassifications of prior year data were made in the accompanying financial statements to conform to the current year presentation.

In accordance with accounting guidance on noncontrolling interests in consolidated financial statements, the Preferred Stock of CL&P and the Preferred Stock of NSTAR Electric, which are not owned by Eversource or its consolidated subsidiaries and are not subject to mandatory redemption, have been presented as noncontrolling interests in the financial statements of Eversource. The Preferred Stock of CL&P and the Preferred Stock of NSTAR Electric are considered to be temporary equity and have been classified between liabilities and permanent shareholders' equity on the balance sheets of Eversource, CL&P and NSTAR Electric due to a provision in the preferred stock agreements of both CL&P and NSTAR Electric that grant preferred stockholders the right to elect a majority of the CL&P and NSTAR Electric Boards of Directors, respectively, should certain conditions exist, such as if preferred dividends are in arrears for a specified amount of time. The Net Income reported in the statements of income and cash flows represents net income prior to apportionment to noncontrolling interests, which is represented by dividends on preferred stock of CL&P and NSTAR Electric.

As of both December 31, 2018 and 2017, Eversource's carrying amount of goodwill was approximately $4.4 billion. Eversource performs an assessment for possible impairment of its goodwill at least annually. Eversource completed its annual goodwill impairment test for each of its reporting units as of October 1, 2018 and determined that no impairment exists. See Note 24B, "Acquisition of Aquarion and Goodwill - Goodwill," for further information.

C. Accounting Standards

Accounting Standards Issued but Not Yet Effective: In February 2016, the FASB issued Accounting Standards Update ("ASU") 2016-02, *Leases (Topic 842)*, which changes existing lease accounting guidance and is required to be applied in the first quarter of 2019. The requirements of the new leases standard include balance sheet recognition of leases deemed to be operating leases and additional disclosure requirements. The recognition, measurement and presentation of expenses and cash flows are not significantly changed. The Company implemented the new leases standard in the first quarter of 2019 and applied the Topic 842 lease criteria to new leases and lease renewals entered into effective on or after January 1, 2019.

In July 2018, the FASB issued ASU 2018-11, *Leases (Topic 842) - Targeted Improvements*, allowing a transition method to adopt the new leases standard on a prospective basis as of the adoption date, with prior periods presented in the financial statements continuing to follow existing lease accounting guidance under Topic 840 (Leases) in the accounting literature. The Company adopted the prospective transition method allowed in ASU 2018-11.

The Company has decided to elect the practical expedient package whereby it does not need to reassess whether or not an existing contract is or contains a lease or whether a lease is an operating or capital lease, and it does not need to reassess initial direct costs for leases. The Company has also elected the practical expedient to not reevaluate land easements existing at adoption if they were not previously accounted for as leases.

The Company determined the impact the ASUs will have on its financial statements by reviewing its lease population and identifying lease data needed for the disclosure requirements. The Company implemented a new lease accounting system in 2019 to ensure ongoing compliance with the ASU's requirements. Eversource recognized approximately $60 million, which includes approximately $25 million at NSTAR Electric, approximately $1 million at CL&P and approximately $1 million at PSNH, of operating lease liabilities and right-of-use assets on their respective balance sheets upon transition at January 1, 2019. Implementation of the new guidance will not have an impact on each company's results of operations and cash flows.

Accounting Standards Recently Adopted: On January 1, 2018, Eversource, CL&P, NSTAR Electric and PSNH adopted ASU 2014-09, *Revenue from Contracts with Customers*, which amended existing revenue recognition guidance, using the modified retrospective method (cumulatively at the date of initial application) applying it only to contracts that were not complete at January 1, 2018. Under this method of adoption, prior year reported results were not restated. Implementation of the ASU did not have a material effect on the results of operations, financial position or cash flows of Eversource, CL&P, NSTAR Electric or PSNH. See Note 22, "Revenues," for further information.

The Company identified an item that was accounted for differently under the new revenue guidance, as compared to the previously existing guidance. As a result of applying guidance on the unit of account under the new standard, purchases of power from and sales of power to ISO-New England are now accounted for net by the hour, rather than net by the month. This change increased Operating Revenues and Purchased Power, Fuel and Transmission by $22.8 million for the year ended December 31, 2018, with no impact on net income.

On January 1, 2018, Eversource adopted ASU 2016-01, *Financial Instruments - Overall: Recognition and Measurement of Financial Assets and Liabilities*. The ASU removed the available-for-sale designation for equity securities, whereby changes in fair value were previously recorded in accumulated other comprehensive income within shareholders' equity, and required changes in fair value of all equity securities to be recorded in earnings effective January 1, 2018. There was no cumulative effect of adoption. Unrealized losses recorded in Other Income, Net were $4.3 million for the year ended December 31, 2018. For further information, see Note 5, "Marketable Securities," to the financial statements.

On January 1, 2018, Eversource, CL&P, NSTAR Electric and PSNH adopted ASU 2017-07, *Compensation – Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. The ASU required separate presentation of service cost from other components of net pension, SERP and PBOP costs, with the other components presented as non-operating income and not subject to capitalization. The ASU has been applied retrospectively for the separate presentation in the income statement of service costs and other components and prospectively in the balance sheet for the capitalization of only the service cost component. As of December 31, 2018, the non-service cost components of net pension, SERP and PBOP costs that were not capitalized in plant were recorded as an increase to regulatory liabilities of $39.8 million, as these amounts continue to be included in rates. See Note 1N, "Summary of Significant Accounting Policies - Other Income, Net," to the financial statements for the portion of pension, SERP and PBOP costs that are presented as non-operating income for the years ended December 31, 2018, 2017 and 2016. For the year ended December 31, 2017, the amounts, which were previously presented within Operations and Maintenance expense on the statements of income, totaled $29.9 million at Eversource, $1.8 million at CL&P, $19.2 million at NSTAR Electric and $5.9 million at PSNH, and have been retrospectively presented within Other Income, Net. For the year ended December 31, 2016, these amounts were $18.6 million at Eversource, $0.7 million at CL&P, $10.5 million at NSTAR Electric and $6.2 million at PSNH.

On January 1, 2018, Eversource, CL&P, NSTAR Electric and PSNH adopted two accounting standards relating to the statement of cash flows; ASU 2016-15, *Classification of Certain Cash Receipts and Cash Payments,* and ASU 2016-18, *Restricted Cash.* As a result of implementing ASU 2016-15, dividends from equity method investments of $19.1 million, $20.0 million, and $0.7 million for the years ended December 31, 2018, 2017, and 2016, respectively, are presented in operating activities at Eversource, for which the 2017 and 2016 amounts were previously classified in investing activities. ASU 2016-18 required that the statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash and restricted cash equivalents. Both standards were applied retrospectively, as required, and neither had a material impact on Eversource's, CL&P's, NSTAR Electric's or PSNH's statements of cash flows. See Note 1P, "Summary of Significant Accounting Policies - Supplemental Cash Flow Information," to the financial statements for a reconciliation of cash and cash equivalents as reported on the balance sheet to the statement of cash flows, which includes amounts described as restricted cash and restricted cash equivalents.

D. Northern Pass

Northern Pass is Eversource's planned 1,090 MW HVDC transmission line that will interconnect from the Québec-New Hampshire border to Franklin, New Hampshire and an associated alternating current radial transmission line between Franklin and Deerfield, New Hampshire. As of December 31, 2018, our capitalized Northern Pass project costs were approximately $307 million.

In March 2018, the New Hampshire Site Evaluation Committee ("NHSEC") issued a written decision denying Northern Pass' siting application after which the Massachusetts EDCs terminated the selection of, and subsequent contract negotiations with, Northern Pass under the Massachusetts Clean Energy RFP. On April 27, 2018, NPT filed a motion for rehearing with the NHSEC, and on July 12, 2018, the NHSEC issued its written decision denying Northern Pass' motion for rehearing. On August 10, 2018, NPT filed an appeal to the New Hampshire Supreme Court, alleging that the NHSEC failed to follow applicable law in its review of the project. On October 12, 2018, the New Hampshire Supreme Court accepted this appeal. Subsequently, the NHSEC transmitted the record of its proceedings to the New Hampshire Supreme Court on December 11, 2018. Briefing of the appeal began on February 4, 2019. The New Hampshire Supreme Court has not set a date for oral argument. NPT intends to continue to pursue NHSEC approval to construct this project.

The March 2018 NHSEC decision denying Northern Pass' siting application caused us to review the recoverability of our Northern Pass project costs in the first quarter of 2018. In this recoverability review, we estimated undiscounted expected project cash flows and compared the result to our estimated project costs to determine whether the recorded amount was recoverable. Our undiscounted cash flows were substantially in excess of our estimated project costs. We completed this analysis and concluded that our project costs were recoverable as of March 31, 2018, based on our expectation that the Northern Pass project remains probable of being placed in service.

Consistent with Eversource's and HQ's long-term relationship to bring clean energy into New England, Eversource and HQ remain committed to Northern Pass and the many benefits this project will bring to our customers and the region. If as a result of future events and changes in circumstances a new recoverability review were to conclude that our project costs are not recoverable, then we would reduce Northern Pass' project costs to the estimated fair value, which could result in most of our $307 million of capitalized project costs being impaired. Such an impairment could have a material adverse effect on our financial position and results of operations.

E. Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and short-term cash investments that are highly liquid in nature and have original maturities of three months or less. At the end of each reporting period, any overdraft amounts are reclassified from Cash and Cash Equivalents to Accounts Payable on the balance sheets.

F. Provision for Uncollectible Accounts

Eversource, including CL&P, NSTAR Electric and PSNH, presents its receivables at estimated net realizable value by maintaining a provision for uncollectible accounts. This provision is determined based upon a variety of judgments and factors, including the application of an estimated uncollectible percentage to each receivable aging category. The estimate is based upon historical collection and write-off experience and management's assessment of collectability from customers. Management continuously assesses the collectability of receivables and adjusts collectability estimates based on actual experience. Receivable balances are written off against the provision for uncollectible accounts when the customer accounts are terminated and these balances are deemed to be uncollectible.

The PURA allows CL&P and Yankee Gas to accelerate the recovery of accounts receivable balances attributable to qualified customers under financial or medical duress (uncollectible hardship accounts receivable) outstanding for greater than 180 days and 90 days, respectively. The DPU allows NSTAR Electric and NSTAR Gas to recover in rates, amounts associated with certain uncollectible hardship accounts receivable. These uncollectible hardship customer account balances are included in Regulatory Assets or Other Long-Term Assets on the balance sheets.

The total provision for both uncollectible accounts and for uncollectible hardship accounts (the uncollectible hardship balance is included in the total provision) is included in Receivables, Net on the balance sheets, and is as follows:

	Total Provision for Uncollectible Accounts		Uncollectible Hardship	
	As of December 31,		As of December 31,	
(Millions of Dollars)	2018	2017	2018	2017
Eversource	$ 212.7	$ 195.7	$ 131.5	$ 122.5
CL&P	88.0	78.9	71.9	65.5
NSTAR Electric	74.5	69.7	42.5	40.3
PSNH	11.1	10.5	—	—

In accordance with new revenue accounting guidance, uncollectible expense associated with customers' accounts receivable included in Operations and Maintenance expense on the statements of income is as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2018	2017	2016
Eversource	$ 61.3	$ 44.5	$ 69.5
CL&P	15.8	5.3	17.6
NSTAR Electric	22.3	21.3	31.7
PSNH	6.4	6.7	7.3

G. CL&P Energy Efficiency Loans

In December 2018, CL&P transferred $41.3 million of its energy efficiency customer loan portfolio to two outside lenders in order to make additional loans to customers. CL&P remains the servicer of the loans and will transmit customer payments to the lenders. Under a three-year agreement with the lenders, additional energy efficiency loans will also be transferred with a maximum amount outstanding under this program of $55 million. The transaction did not qualify as a sale for accounting purposes, and the amounts of the loans ($18.5 million and $22.8 million as of December 31, 2018 in current and long-term, respectively), included in Accounts Receivable, Net and Other Long-Term Assets, are offset by Other Current Liabilities and Other Long-Term Liabilities on CL&P's balance sheet.

H. Fuel, Materials, Supplies and Inventory

Fuel, Materials, Supplies and Inventory include natural gas inventory, materials and supplies purchased primarily for construction or operation and maintenance purposes, and RECs. Inventory is valued at the lower of cost or net realizable value. RECs are purchased from suppliers of renewable sources of generation and are used to meet state mandated Renewable Portfolio Standards requirements. The carrying amounts of fuel, materials and supplies, and RECs, which are included in Current Assets on the balance sheets, were as follows:

	As of December 31,							
	2018				2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Fuel	$ 33.1	$ —	$ —	$ —	$ 29.7	$ —	$ —	$ —
Materials and Supplies	126.1	44.5	48.6	24.3	117.1	44.4	45.1	18.5
RECs	78.8	—	65.6	13.2	76.3	4.0	50.4	21.8
Total - Current	$ 238.0	$ 44.5	$ 114.2	$ 37.5	$ 223.1	$ 48.4	$ 95.5	$ 40.3

I. Fair Value Measurements

Fair value measurement guidance is applied to derivative contracts that are not elected or designated as "normal purchases" or "normal sales" ("normal") and to the marketable securities held in trusts. Fair value measurement guidance is also applied to valuations of the investments used to calculate the funded status of pension and PBOP plans, the nonrecurring fair value measurements of nonfinancial assets such as goodwill and AROs, and the estimated fair value of preferred stock, long-term debt and RRBs.

Fair Value Hierarchy: In measuring fair value, Eversource uses observable market data when available in order to minimize the use of unobservable inputs. Inputs used in fair value measurements are categorized into three fair value hierarchy levels for disclosure purposes. The entire fair value measurement is categorized based on the lowest level of input that is significant to the fair value measurement. Eversource evaluates the classification of assets and liabilities measured at fair value on a quarterly basis, and Eversource's policy is to recognize transfers between levels of the fair value hierarchy as of the end of the reporting period. The three levels of the fair value hierarchy are described below:

Level 1 - Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 - Inputs are quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations in which all significant inputs are observable.

Level 3 - Quoted market prices are not available. Fair value is derived from valuation techniques in which one or more significant inputs or assumptions are unobservable. Where possible, valuation techniques incorporate observable market inputs that can be validated to external sources such as industry exchanges, including prices of energy and energy-related products.

Uncategorized - Investments that are measured at net asset value are not categorized within the fair value hierarchy.

Determination of Fair Value: The valuation techniques and inputs used in Eversource's fair value measurements are described in Note 4, "Derivative Instruments," Note 5, "Marketable Securities," Note 6, "Asset Retirement Obligations," Note 10A, "Employee Benefits – Pension Benefits and Postretirement Benefits Other Than Pension," Note 15, "Fair Value of Financial Instruments" and Note 24B, "Acquisition of Aquarion and Goodwill - Goodwill" to the financial statements.

J. Derivative Accounting

Many of the electric and natural gas companies' contracts for the purchase and sale of energy or energy-related products are derivatives. The accounting treatment for energy contracts entered into varies and depends on the intended use of the particular contract and on whether or not the contract is a derivative. For the regulated companies, regulatory assets or regulatory liabilities are recorded to offset the fair values of derivative contracts related to energy and energy-related products, as contract settlements are recovered from, or refunded to, customers in future rates.

The application of derivative accounting is complex and requires management judgment in the following respects: identification of derivatives and embedded derivatives, election and designation of a contract as normal, and determination of the fair value of derivative contracts. All of these judgments can have a significant impact on the financial statements.

The judgment applied in the election of a contract as normal (and resulting accrual accounting) includes the conclusion that it is probable at the inception of the contract and throughout its term that it will result in physical delivery of the underlying product and that the quantities will be used or sold by the business in the normal course of business. If facts and circumstances change and management can no longer support this conclusion, then a contract cannot be considered normal, accrual accounting is terminated, and fair value accounting is applied prospectively.

The fair value of derivative contracts is based upon the contract terms and conditions and the underlying market price or fair value per unit. When quantities are not specified in the contract, the Company determines whether the contract has a determinable quantity by using amounts referenced in default provisions and other relevant sections of the contract. The fair value of derivative assets and liabilities with the same counterparty are offset and recorded as a net derivative asset or liability on the balance sheets.

All changes in the fair value of derivative contracts are recorded as regulatory assets or liabilities and do not impact net income.

For further information regarding derivative contracts, see Note 4, "Derivative Instruments," to the financial statements.

K. Investments

Investments are included in Other Long-Term Assets on the balance sheets and earnings impacts from these equity investments are included in Other Income, Net on the statements of income.

Strategic, Infrastructure and Other Investments: As of December 31, 2018 and 2017, Eversource had investments totaling $463.7 million and $277.6 million, respectively. As of December 31, 2018 and 2017, Eversource's investments included a 50 percent ownership in Bay State Wind, an offshore wind project of $234.3 million and $30.2 million, respectively, a 15 percent ownership interest in a FERC-regulated natural gas transmission business of $155.0 million and $159.6 million, respectively, a 37.2 percent (14.5 percent of which related to NSTAR Electric) ownership interest in two companies that transmit hydro-electricity imported from the Hydro-Quebec system in Canada of $19.5 million and $17.7 million, respectively, other investments totaling $54.9 million and $38.8 million, respectively, and a 40 percent ownership interest in Access Northeast of $31.3 million as of December 31, 2017. NSTAR Electric's investments totaled $7.6 million and $6.9 million, respectively, as of December 31, 2018 and 2017.

Impairment of Access Northeast: Access Northeast is a natural gas pipeline and storage project jointly owned by Eversource, Enbridge, Inc. ("Enbridge") and National Grid plc ("National Grid"), through Algonquin Gas Transmission, LLC ("AGT"). Equity method investments are assessed for impairment when conditions exist that indicate that the fair value of the investment is less than book value. If the decline in value is considered to be other-than-temporary, the investment is written down to its estimated fair value, which establishes a new cost basis in the investment. Impairment evaluations involve a significant degree of judgment and estimation, including identifying circumstances that indicate an impairment may exist and developing undiscounted future cash flows.

In 2015 and 2016, AGT sought to secure long-term natural gas pipeline capacity contracts with EDCs in Massachusetts, Connecticut, New Hampshire, Maine, and Rhode Island. Subsequently, in 2016, the Massachusetts Supreme Judicial Court and the NHPUC each ruled that state statutes precluded the state regulatory agencies from approving those contracts in Massachusetts and New Hampshire, respectively. The New Hampshire Supreme Court overruled the NHPUC decision in May 2018. Legislative changes are needed in Massachusetts to allow the DPU to approve natural gas pipeline capacity contracts. No such changes have occurred during any legislative session to date.

In September 2018, a series of non-Eversource natural gas explosions in eastern Massachusetts resulted in widespread property and system damage, personal injuries, and a fatality. As a result of these events, compounded by the failure to secure Massachusetts legislation to date, we believe there is significant uncertainty around the future timing of, and ability to secure, needed legislative change affecting the natural gas industry and pipeline expansion, which may significantly delay the completion of the Access Northeast project.

Eversource identified the September 2018 natural gas series of explosions, compounded by the adverse legislative environment, as negative evidence that indicated potential impairment. Our impairment assessment used a discounted cash flow approach, including consideration of the severity and duration of any decline in fair value of our investment in the project, and involved significant management judgment and estimation, including projections of the project's discounted cash flows and assumptions about exit price. In the third quarter of 2018, management determined that the future cash flows of the Access Northeast project were uncertain and could no longer be reasonably estimated and that the book value of our equity method investment was not recoverable. As a result, Eversource recorded an other-than-temporary impairment of $32.9 million within Other Income, Net on our statement of income in 2018, which represented the full carrying value of our equity method investment.

Regional Decommissioned Nuclear Companies: CL&P, NSTAR Electric and PSNH own common stock in three regional nuclear generation companies (CYAPC, YAEC and MYAPC, collectively referred to as the "Yankee Companies"), each of which owned a single nuclear generating facility that has been decommissioned. For CL&P, NSTAR Electric and PSNH, the respective investments in CYAPC, YAEC and MYAPC are accounted for under the equity method and are included in Other Long-Term Assets on their respective balance sheets. For CL&P, NSTAR Electric and PSNH, these investments totaled $1.3 million, $0.9 million and $0.3 million as of both December 31, 2018 and 2017. Eversource consolidates CYAPC and YAEC because CL&P's, NSTAR Electric's and PSNH's combined ownership and voting interests in each of these entities is greater than 50 percent. For further information on the Yankee Companies, see Note 12C, "Commitments and Contingencies – Spent Nuclear Fuel Obligations – Yankee Companies," to the financial statements.

Equity in Earnings and Dividends from Equity Method Investments: For the years ended December 31, 2018, 2017 and 2016, Eversource had equity in earnings, net of impairment, of unconsolidated affiliates of $3.8 million, $27.4 million, and $0.2 million, respectively. Eversource received dividends from its equity method investees of $22.3 million, $20.0 million and $0.1 million, respectively, for the years ended December 31, 2018, 2017 and 2016.

2019 Investment - Revolution Wind and South Fork Wind: On February 8, 2019, Eversource and Ørsted entered into a 50-50 partnership for key offshore wind assets in the Northeast. Eversource paid approximately $225 million for a 50 percent interest in Ørsted's Revolution Wind and South Fork Wind power projects, as well as the 257-square-mile tract off the coasts of Massachusetts and Rhode Island, owned by North East Offshore LLC. Upon execution of the transaction, Eversource parent issued a guaranty on behalf of its subsidiary, Eversource Investment LLC. Eversource parent will guarantee, as a primary obligor, the financial obligations, primarily all post-Closing payment obligations of Eversource Investment LLC, under the Sale and Purchase Agreement and an Irrevocable Equity Commitment Letter with Ørsted in an amount not to exceed $127.6 million. Eversource parent's obligations under the guaranty expire upon the full, final and indefeasible payment of the guaranteed obligations.

L. Operating Expenses

Costs related to fuel and natural gas included in Purchased Power, Fuel and Transmission on the statements of income were as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	**2018**	**2017**	**2016**
Eversource - Natural Gas and Fuel	$ 442.6	$ 432.5	$ 372.2
PSNH - Fuel	7.9	43.4	45.0

PSNH completed the sale of its generation assets in 2018.

M. Allowance for Funds Used During Construction

AFUDC represents the cost of borrowed and equity funds used to finance construction and is included in the cost of the electric, natural gas and water companies' utility plant on the balance sheet. The portion of AFUDC attributable to borrowed funds is recorded as a reduction of Interest Expense, and the AFUDC related to equity funds is recorded as Other Income, Net on the statements of income. AFUDC costs are recovered from customers over the service life of the related plant in the form of increased revenue collected as a result of higher depreciation expense.

The average AFUDC rate is based on a FERC-prescribed formula using the cost of a company's short-term financings and capitalization (preferred stock, long-term debt and common equity), as appropriate. The average rate is applied to average eligible CWIP amounts to calculate AFUDC.

AFUDC costs and the weighted-average AFUDC rates were as follows:

Eversource	For the Years Ended December 31,		
(Millions of Dollars, except percentages)	2018	2017	2016
Borrowed Funds	$ 19.7	$ 12.5	$ 10.8
Equity Funds	44.0	34.4	26.2
Total AFUDC	$ 63.7	$ 46.9	$ 37.0
Average AFUDC Rate	4.9%	5.1%	4.4%

	For the Years Ended December 31,								
	2018			2017			2016		
(Millions of Dollars except percentages)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Borrowed Funds	$ 6.3	$ 7.8	$ 1.3	$ 5.1	$ 4.8	$ 0.7	$ 3.3	$ 5.3	$ 0.8
Equity Funds	12.2	15.6	—	12.1	10.2	—	6.3	10.2	0.3
Total AFUDC	$ 18.5	$ 23.4	$ 1.3	$ 17.2	$ 15.0	$ 0.7	$ 9.6	$ 15.5	$ 1.1
Average AFUDC Rate	5.8%	5.0%	0.7%	6.2%	5.0%	0.7%	4.7%	3.2%	1.0%

N. Other Income, Net

The components of Other Income, Net on the statements of income were as follows:

Eversource	For the Years Ended December 31,		
(Millions of Dollars)	2018	2017	2016
Pension, SERP and PBOP Non-Service Income Components (1)	$ 60.8	$ 29.9	$ 18.6
AFUDC Equity	44.0	34.4	26.2
Equity in Earnings, Net of Impairment (2)	3.8	27.4	0.2
Investment Income/(Loss)	(4.0)	7.5	8.5
Interest Income (3)	18.1	8.3	11.0
Gains on Sales of Property	5.1	—	—
Other	0.6	0.4	—
Total Other Income, Net (1)	$ 128.4	$ 107.9	$ 64.5

	For the Years Ended December 31,								
	2018			2017			2016		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Pension, SERP and PBOP Non-Service Income Components (1)	$ 9.5	$ 36.0	$ 9.9	$ 1.8	$ 19.2	$ 5.9	$ 0.7	$ 10.5	$ 6.2
AFUDC Equity	12.2	15.6	—	12.1	10.2	—	6.3	10.2	0.3
Equity in Earnings	0.1	0.7	—	—	0.3	—	0.1	0.3	—
Investment Income/(Loss)	(3.0)	(0.5)	(0.8)	4.5	2.6	1.6	(1.5)	(0.3)	(0.7)
Interest Income (3)	3.7	0.8	14.1	4.6	1.8	2.2	8.6	0.6	1.8
Gain on Sale of Property	—	0.5	4.4	—	—	—	—	—	—
Other	0.2	—	0.1	—	—	0.1	—	—	—
Total Other Income, Net (1)	$ 22.7	$ 53.1	$ 27.7	$ 23.0	$ 34.1	$ 9.8	$ 14.2	$ 21.3	$ 7.6

(1) As a result of the adoption of new accounting guidance, the non-service related components of pension, SERP and PBOP benefit costs are presented as non-operating income and recorded in Other Income, Net on the statements of income. The 2017 and 2016 amounts, which were previously presented within Operations and Maintenance expense on the statements of income, have been retrospectively presented within Other Income, Net for the years ended December 31, 2017 and 2016. Eversource elected the practical expedient in the accounting guidance that allows the Company to use the amounts disclosed in its Pension Benefits and Postretirement Benefits Other Than Pension footnote for the prior period presentations as the estimation basis for applying the retrospective presentation requirements.

(2) For the year ended December 31, 2018, equity in earnings, net of impairment, of unconsolidated affiliates includes an other-than-temporary impairment of $32.9 million in the Access Northeast project investment. See Note 1K, "Summary of Significant Accounting Policies - Investments," for further information. Equity in earnings includes $17.6 million and $9.7 million of unrealized gains in 2018 and 2017, respectively, and $1.7 million of unrealized losses in 2016 associated with an equity method investment in a renewable energy fund.

(3) See Note 2, "Regulatory Accounting," for interest income recognized in 2018 for the equity return component of carrying charges on storm costs at PSNH.

O. Other Taxes

Eversource's companies that serve customers in Connecticut collect gross receipts taxes levied by the state of Connecticut from their customers. These gross receipts taxes are recorded separately with collections in Operating Revenues and with payments in Taxes Other Than Income Taxes on the statements of income as follows:

	For the Years Ended December 31,		
(Millions of Dollars)	2018	2017	2016
Eversource	$ 161.9	$ 157.4	$ 162.7
CL&P	141.4	137.5	145.2

As agents for state and local governments, Eversource's companies that serve customers in Connecticut and Massachusetts collect certain sales taxes that are recorded on a net basis with no impact on the statements of income.

Separate from the amounts above are $46.8 million and $25.4 million of amounts recorded as Taxes Other than Income Taxes in 2018 and 2017, respectively, related to the future remittance to the State of Connecticut of energy efficiency funds collected from customers in Operating Revenues.

These amounts are recorded separately with collections in Operating Revenues and expenses in Taxes Other than Income Taxes on the Eversource and CL&P statements of income.

P. Supplemental Cash Flow Information

Eversource
(Millions of Dollars)

	As of and For the Years Ended December 31,		
	2018	2017	2016
Cash Paid/(Received) During the Year for:			
Interest, Net of Amounts Capitalized	$ 503.2	$ 419.1	$ 398.1
Income Taxes	158.8	30.8	(135.5)
Non-Cash Investing Activities:			
Plant Additions Included in Accounts Payable (As of)	435.9	379.5	301.5

	As of and For the Years Ended December 31,								
	2018			2017			2016		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Cash Paid/(Received) During the Year for:									
Interest, Net of Amounts Capitalized	$ 149.7	$ 122.1	$ 40.5	$ 144.6	$ 124.6	$ 45.9	$ 143.3	$ 112.9	$ 46.5
Income Taxes	66.1	120.0	27.3	68.8	95.5	26.1	(73.9)	66.0	(36.0)
Non-Cash Investing Activities:									
Plant Additions Included in Accounts Payable (As of)	106.1	116.5	81.7	132.5	116.5	44.4	116.2	87.0	37.9

In December 2018, CYAPC paid $145 million to the DOE to partially settle its pre-1983 spent nuclear fuel obligation. In 2016, as a result of damages awarded to the Yankee Companies for spent nuclear fuel lawsuits against the DOE described in Note 12C, "Commitments and Contingencies – Spent Nuclear Fuel Obligations – Yankee Companies," CYAPC and YAEC received total proceeds of $52.2 million, which were classified as operating activities on the Eversource consolidated statements of cash flows. CYAPC returned $6.8 million of these proceeds to its non-affiliated member companies. In addition, CL&P, NSTAR Electric and PSNH received a total distribution of $14.4 million from MYAPC as a result of DOE Phase III proceeds and a distribution from its spent nuclear fuel trust.

The following table reconciles cash and cash equivalents as reported on the balance sheets to the cash, cash equivalents, and restricted cash as reported on the statements of cash flows:

	As of December 31,							
	2018				2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Cash and Cash Equivalents as reported on the Balance Sheets	$ 108.1	$ 87.7	$ 1.6	$ 1.4	$ 38.2	$ 6.0	$ 1.8	$ 0.9
Restricted cash included in:								
Prepayments and Other Current Assets	72.1	3.5	13.0	47.5	24.4	3.1	12.8	0.5
Marketable Securities	25.9	0.4	0.1	0.6	23.3	0.5	0.1	0.8
Other Long-Term Assets	3.2	—	—	3.2	—	—	—	—
Cash, Cash Equivalents, and Restricted Cash reported on the Statements of Cash Flows	$ 209.3	$ 91.6	$ 14.7	$ 52.7	$ 85.9	$ 9.6	$ 14.7	$ 2.2

Restricted cash included in Prepayments and Other Current Assets and Other Long-Term Assets, shown above, primarily represents cash collections related to the PSNH RRB customer charges that are held in trust and required ISO-NE cash deposits. Restricted cash included in Marketable Securities, shown above, represents money market funds held in trusts to fund certain non-qualified executive benefits and restricted trusts to fund CYAPC and YAEC's spent nuclear fuel storage facilities obligations.

As a result of implementing new accounting guidance for the statement of cash flows, the reclassification of the change in restricted cash balances, which was previously classified as operating activities, resulted in a decrease of $28.8 million in the total cash and restricted cash change for the year ended December 31, 2017 and an increase of $32.4 million in the total cash and restricted cash change for the year ended December 31, 2016.

Q. Related Parties

Eversource Service, Eversource's service company, provides centralized accounting, administrative, engineering, financial, information technology, legal, operational, planning, purchasing, and other services to Eversource's companies. The Rocky River Realty Company, Renewable Properties, Inc. and Properties, Inc., three other Eversource subsidiaries, construct, acquire or lease some of the property and facilities used by Eversource's companies.

As of both December 31, 2018 and 2017, CL&P, NSTAR Electric and PSNH had long-term receivables from Eversource Service in the amounts of $25.0 million, $5.5 million and $3.8 million, respectively, which were included in Other Long-Term Assets on the balance sheets. These amounts related to the funding of investments held in trust by Eversource Service in connection with certain postretirement benefits for CL&P, NSTAR Electric and PSNH employees and have been eliminated in consolidation on the Eversource financial statements.

Included in the CL&P, NSTAR Electric and PSNH balance sheets as of December 31, 2018 and 2017 were Accounts Receivable from Affiliated Companies and Accounts Payable to Affiliated Companies relating to transactions between CL&P, NSTAR Electric and PSNH and other subsidiaries that are wholly-owned by Eversource. These amounts have been eliminated in consolidation on the Eversource financial statements.

2. REGULATORY ACCOUNTING

Eversource's utility companies are subject to rate regulation that is based on cost recovery and meets the criteria for application of accounting guidance for rate-regulated operations, which considers the effect of regulation on the timing of the recognition of certain revenues and expenses. The regulated companies' financial statements reflect the effects of the rate-making process. The rates charged to the customers of Eversource's regulated companies are designed to collect each company's costs to provide service, including a return on investment.

Management believes it is probable that each of the regulated companies will recover its respective investments in long-lived assets, including regulatory assets. If management were to determine that it could no longer apply the accounting guidance applicable to rate-regulated enterprises to any of the regulated companies' operations, or if management could not conclude it is probable that costs would be recovered from customers in future rates, the costs would be charged to net income in the period in which the determination is made.

Regulatory Assets: The components of regulatory assets were as follows:

	As of December 31,							
	2018				2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Benefit Costs	$ 1,914.8	$ 424.7	$ 544.4	$ 169.6	$ 2,068.8	$ 469.2	$ 560.7	$ 212.3
Income Taxes, Net	728.6	454.4	105.9	8.3	768.9	453.8	113.2	21.7
Securitized Stranded Costs	608.4	—	—	608.4	—	—	—	—
Deferred Costs from Generation Asset Sale	—	—	—	—	516.1	—	—	516.1
Storm Restoration Costs, Net	576.0	302.6	212.9	60.5	404.8	216.7	146.6	41.5
Regulatory Tracker Mechanisms	316.0	33.2	169.1	67.3	509.9	85.3	273.0	116.4
Derivative Liabilities	356.5	356.5	—	—	367.2	362.3	—	—
Goodwill-related	348.4	—	299.1	—	365.2	—	313.6	—
Asset Retirement Obligations	89.2	32.3	42.2	3.3	101.0	30.3	39.0	17.0
Other Regulatory Assets	208.0	27.0	64.6	12.1	137.4	27.6	78.4	15.8
Total Regulatory Assets	5,145.9	1,630.7	1,438.2	929.5	5,239.3	1,645.2	1,524.5	940.8
Less: Current Portion	514.8	125.2	241.7	67.2	741.9	200.3	333.9	130.1
Total Long-Term Regulatory Assets	$ 4,631.1	$ 1,505.5	$ 1,196.5	$ 862.3	$ 4,497.4	$ 1,444.9	$ 1,190.6	$ 810.7

Benefit Costs: Eversource's Pension, SERP and PBOP Plans are accounted for in accordance with accounting guidance on defined benefit pension and other PBOP plans. The liability (or asset) recorded by the regulated companies to recognize the funded status of their retiree benefit plans is offset by a regulatory asset (or offset by a regulatory liability in the case of a benefit plan asset) in lieu of a charge to Accumulated Other Comprehensive Income/(Loss), reflecting ultimate recovery from customers through rates. The regulatory asset (or regulatory liability) is amortized as the actuarial gains and losses and prior service cost are amortized to net periodic benefit cost for the pension and PBOP plans. All amounts are remeasured annually. Regulatory accounting is also applied to the portions of Eversource's service company costs that support the regulated companies, as these amounts are also recoverable. As these regulatory assets or regulatory liabilities do not represent a cash outlay for the regulated companies, no carrying charge is recovered from customers. The decrease in the regulatory asset balance at PSNH as of December 31, 2018 was due in part to the generation divestiture and the securitization of remaining generation costs.

CL&P, NSTAR Electric and PSNH recover benefit costs related to their distribution and transmission operations from customers in rates as allowed by their applicable regulatory commissions. NSTAR Electric recovers qualified pension and PBOP expenses related to its distribution operations through a rate reconciling mechanism that fully tracks the change in net pension and PBOP expenses each year.

Income Taxes, Net: The tax effect of temporary book-tax differences (differences between the periods in which transactions affect income in the financial statements and the periods in which they affect the determination of taxable income, including those differences relating to uncertain tax positions) is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions and accounting guidance for income taxes. Differences in income taxes between the accounting guidance and the rate-making treatment of the applicable regulatory commissions are recorded as regulatory assets. As these assets are offset by deferred income tax liabilities, no carrying charge is collected. The amortization period of these assets varies depending on the nature and/or remaining life of the underlying assets and liabilities. For further information regarding income taxes, see Note 11, "Income Taxes," to the financial statements.

Securitized Stranded Costs and Deferred Costs from Generation Asset Sale: On May 8, 2018, a subsidiary of PSNH issued $635.7 million of securitized RRBs to finance PSNH's unrecovered remaining costs associated with the divestiture of its generation assets. Securitized regulatory assets, which are not earning an equity return, are being recovered over the amortization period of the associated RRBs. The PSNH RRBs are expected to be repaid by February 1, 2033. The unrecovered costs related to the difference between the carrying value and the fair value less costs to sell PSNH's thermal generation assets, and were reflected as Deferred Costs from Generation Asset Sale in the table above as of December 31, 2017. As of December 31, 2018, these costs are reflected in the Securitized Stranded Costs balance. For further information, see Note 13, "Generation Asset Sale."

Storm Restoration Costs, Net: The storm restoration cost deferrals relate to costs incurred for storm events at CL&P, NSTAR Electric and PSNH that each company expects to recover from customers. A storm must meet certain criteria to qualify for deferral and recovery with the criteria specific to each state jurisdiction and utility company. Once a storm qualifies for recovery, all qualifying expenses incurred during storm restoration efforts are deferred and recovered from customers. Costs for storms that do not meet the specific criteria are expensed as incurred. In addition to storm restoration costs, CL&P and PSNH are each allowed to recover pre-staging storm costs. Management believes storm restoration costs deferred were prudently incurred and meet the criteria for specific cost recovery in Connecticut, Massachusetts and New Hampshire, and that recovery from customers is probable through the applicable regulatory recovery processes. Each electric utility company either recovers a carrying charge on its deferred storm restoration cost regulatory asset balance or the regulatory asset balance is included in rate base.

In 2018, several significant storms caused extensive damage to our electric distribution systems and significant customer outages across all three states. These storms resulted in deferred storm restoration costs of approximately $266 million ($148 million for CL&P, $94 million for NSTAR Electric, and $24 million for PSNH), which were reflected in Storm Restoration Costs, Net in the table above as of December 31, 2018.

On September 17, 2018, the NHPUC approved the recovery of $49 million, plus carrying charges, in storm costs incurred from August 2011 through March 2013 and the transfer of funding from PSNH’s major storm reserve to offset those costs. The costs of these storms (excluding the equity return component of the carrying charges) were deferred as regulatory assets, and the funding reserve collected from customers was accrued as a regulatory liability. The storm cost deferral is separate from the major storm funding reserve that is being collected from customers. As a result of the duration of time between incurring storm costs in August 2011 through March 2013 and final approval from the NHPUC in 2018, PSNH recognized $8.7 million (pre-tax) for the equity return component of the carrying charges, which have been collected from customers, within Other Income, Net on our statement of income in 2018. Storm costs incurred from December 2013 through April 2016 have been audited by the NHPUC staff and are pending NHPUC approval.

Regulatory Tracker Mechanisms: The regulated companies' approved rates are designed to recover costs incurred to provide service to customers. The regulated companies recover certain of their costs on a fully-reconciling basis through regulatory commission-approved tracking mechanisms. The differences between the costs incurred (or the rate recovery allowed) and the actual revenues are recorded as regulatory assets (for undercollections) or as regulatory liabilities (for overcollections) to be included in future customer rates each year. Carrying charges are recovered in rates on all material regulatory tracker mechanisms.

CL&P, NSTAR Electric and PSNH each recover, on a fully reconciling basis, the costs associated with the procurement of energy, transmission related costs from FERC-approved transmission tariffs, energy efficiency programs, low income assistance programs, certain uncollectible accounts receivable for hardship customers, and restructuring and stranded costs as a result of deregulation, and additionally for the Massachusetts utilities, pension and PBOP benefits and net metering for distributed generation. Energy procurement costs at NSTAR Electric include the costs related to its solar power facilities.

CL&P, NSTAR Electric (effective February 1, 2018 as a result of a DPU-approved rate case decision), Yankee Gas (effective November 15, 2018 as a result of a PURA-approved rate case settlement agreement) and NSTAR Gas each have a regulatory commission approved revenue decoupling mechanism. Distribution revenues are decoupled from customer sales volumes, where applicable, which breaks the relationship between sales volumes and revenues recognized. Each company reconciles its annual base distribution rate recovery amount to the pre-established levels of baseline distribution delivery service revenues. Any difference between the allowed level of distribution revenue and the actual amount realized during a 12-month period is adjusted through rates in the following period.

Derivative Liabilities: Regulatory assets are recorded as an offset to derivative liabilities and relate to the fair value of contracts used to purchase energy and energy-related products that will be recovered from customers in future rates. These assets are excluded from rate base and are being recovered as the actual settlements occur over the duration of the contracts. See Note 4, "Derivative Instruments," to the financial statements for further information on these contracts.

Goodwill-related: The goodwill regulatory asset originated from a 1999 transaction, and the DPU allowed its recovery in NSTAR Electric and NSTAR Gas rates. This regulatory asset is currently being amortized and recovered from customers in rates without a carrying charge over a 40-year period, and as of December 31, 2018, there were 21 years of amortization remaining.

Asset Retirement Obligations: The costs associated with the depreciation of the regulated companies' ARO assets and accretion of the ARO liabilities are recorded as regulatory assets in accordance with regulatory accounting guidance. The regulated companies' ARO assets, regulatory assets and liabilities offset and are excluded from rate base. These costs are being recovered over the life of the underlying property, plant and equipment.

Other Regulatory Assets: Other Regulatory Assets primarily include contractual obligations associated with the remaining nuclear fuel storage costs of the CYAPC, YAEC and MYAPC nuclear facilities, environmental remediation costs, losses associated with the reacquisition or redemption of long-term debt, certain uncollectible accounts receivable for hardship customers, certain merger-related costs allowed for recovery, water tank painting costs, and various other items.

Regulatory Costs in Long-Term Assets: Eversource's regulated companies had $122.9 million (including $42.1 million for CL&P, $49.3 million for NSTAR Electric and $12.2 million for PSNH) and $105.8 million (including $18.2 million for CL&P, $42.7 million for NSTAR Electric and $27.2 million for PSNH) of additional regulatory costs as of December 31, 2018 and 2017, respectively, that were included in long-term assets on the balance sheets. These amounts represent incurred costs for which recovery has not yet been specifically approved by the applicable regulatory agency. However, based on regulatory policies or past precedent on similar costs, management believes it is probable that these costs will ultimately be approved and recovered from customers in rates.

Equity Return on Regulatory Assets: For rate-making purposes, the regulated companies recover the carrying costs related to their regulatory assets. For certain regulatory assets, the carrying cost recovered includes an equity return component. This equity return, which is not recorded on the balance sheets, totaled $0.7 million and $1.0 million for CL&P as of December 31, 2018 and 2017, respectively. These carrying costs will be recovered from customers in future rates. As of December 31, 2018 and 2017, this equity return, which is not recorded on the balance sheets, totaled $12.0 million and $42.0 million, respectively, for PSNH. The 2017 amount included $25 million of equity return on the Clean Air Project costs that PSNH had agreed not to bill customers as part of the generation divestiture settlement agreement. PSNH sold its generation assets in 2018.

Regulatory Liabilities: The components of regulatory liabilities were as follows:

	As of December 31,							
	2018				2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
EDIT due to Tax Cuts and Jobs Act	$ 2,883.0	$ 1,031.0	$ 1,103.7	$ 396.4	$ 2,882.0	$ 1,031.6	$ 1,087.9	$ 405.1
Cost of Removal	521.0	39.9	307.1	22.1	502.1	23.2	293.8	37.9
Benefit Costs	91.2	—	76.9	—	132.3	—	112.6	—
Regulatory Tracker Mechanisms	309.0	89.5	163.7	48.3	136.7	34.6	77.8	5.0
AFUDC - Transmission	70.7	47.4	23.3	—	67.1	48.8	18.3	—
Revenue Subject to Refund due to Tax Cuts and Jobs Act	24.6	—	—	12.6	—	—	—	—
Other Regulatory Liabilities	80.2	24.0	29.2	4.2	45.2	12.9	3.7	2.7
Total Regulatory Liabilities	3,979.7	1,231.8	1,703.9	483.6	3,765.4	1,151.1	1,594.1	450.7
Less: Current Portion	370.2	109.6	190.6	55.5	128.1	39.0	79.6	6.3
Total Long-Term Regulatory Liabilities	$ 3,609.5	$ 1,122.2	$ 1,513.3	$ 428.1	$ 3,637.3	$ 1,112.1	$ 1,514.5	$ 444.4

EDIT due to Tax Cuts and Jobs Act: Pursuant to the "Tax Cuts and Jobs Act" (the "Act"), which became law on December 22, 2017, Eversource remeasured its existing deferred federal income tax balances as of December 31, 2017 to reflect the decrease in the U.S. federal corporate income tax rate from 35 percent to 21 percent. The remeasurement resulted in provisional regulated excess accumulated deferred income tax (excess ADIT or EDIT) liabilities that will benefit our customers in future periods and were recognized as regulatory liabilities on the balance sheet. We estimate that approximately 85 percent of the provisional regulated EDIT liabilities relate to property, plant, and equipment with remaining useful lives estimated to be in excess of 35 years. These amounts are subject to IRS normalization rules and will be returned to customers using the same timing as the remaining useful lives of the underlying assets that gave rise to the ADIT liabilities.

Eversource's regulated companies are in the process of, or will be, refunding the EDIT liabilities to customers based on orders issued by applicable state regulatory commissions. For CL&P, amounts related to the EDIT liabilities will be incorporated as refunds to customers in May 1, 2019 base distribution rates. For NSTAR Electric (effective January 1, 2019) and NSTAR Gas (effective February 1, 2019), refunds related to EDIT will occur in rates through a new reconciling factor. Effective November 15, 2018, Yankee Gas' distribution rates charged to customers began to reflect the refund of EDIT. For PSNH, EDIT refunds will be addressed as part of the next distribution rate case filing. The EDIT balance related to PSNH's divested generation assets has been included as a component of the securitization of the stranded generation assets and has started to be refunded to customers via the Stranded Cost Recovery Charge effective August 1, 2018. For our transmission companies, the refund of excess ADIT to customers will be made based on future guidance from FERC.

Cost of Removal: Eversource's regulated companies currently recover amounts in rates for future costs of removal of plant assets over the lives of the assets. The estimated cost to remove utility assets from service is recognized as a component of depreciation expense, and the cumulative amount collected from customers but not yet expended is recognized as a regulatory liability.

AFUDC - Transmission: Regulatory liabilities were recorded by CL&P and NSTAR Electric for AFUDC accrued on certain reliability-related transmission projects to reflect local rate base recovery. These regulatory liabilities will be amortized over the depreciable life of the related transmission assets.

Revenue Subject to Refund due to Tax Cuts and Jobs Act: Eversource established a regulatory liability, recorded as a reduction to revenue, to reflect the difference between the 35 percent federal corporate income tax rate included in rates charged to customers and the 21 percent federal corporate income tax rate, effective January 1, 2018 as a result of the Tax Cuts and Jobs Act, until rates billed to customers reflect the lower federal tax rate. Effective May 1, 2018, CL&P adjusted rates billed to customers to reflect the lower federal income tax rate prospectively and, as of December 31,

2018, fully refunded its regulatory liability associated with the higher federal corporate income tax rate billed to customers in the period between January 1, 2018 through April 30, 2018. Effective November 15, 2018, Yankee Gas adjusted distribution rates to reflect the lower federal income tax rate prospectively and to refund its regulatory liability associated with the higher federal corporate income tax rate billed to customers in the period between January 1, 2018 through November 14, 2018. Although Yankee Gas' new rates were effective January 1, 2019, the provisions of the settlement agreement took effect November 15, 2018. For NSTAR Electric and NSTAR Gas, a December 2018 DPU order indicated that the DPU will not require a revision to base rates for any potential refunds associated with the higher federal corporate income tax rate billed to customers in the period between January 1, 2018 to the effective dates of each company's rate changes (effective February 1, 2018 for NSTAR Electric and July 1, 2018 for NSTAR Gas). PSNH and Aquarion will refund the overcollection in distribution rates from January 1, 2018 to customers in a future period. PSNH will adjust distribution rates to reflect the prospective lower federal income tax rate effective July 1, 2019, or earlier if a rate case is filed for rates effective prior to July 1, 2019.

Effective January 1, 2018, local transmission service rates were updated to reflect the lower U.S. federal corporate income tax rate that resulted from the act. On June 28, 2018, FERC granted a one-time tariff waiver related to the federal corporate income tax rate so that effective June 1, 2018, the regional transmission service rates reflect the reduced federal corporate income tax rate at 21 percent. The refund of excess ADIT to customers will be made based on future guidance from FERC.

FERC ROE Complaints: As of December 31, 2018, Eversource has a reserve established for the second ROE complaint in the pending FERC ROE complaint proceedings, which was recorded as a regulatory liability and is reflected within Regulatory Tracker Mechanisms in the table above. The cumulative pre-tax reserve (excluding interest) as of December 31, 2018 totaled $39.1 million for Eversource (including $21.4 million for CL&P, $14.6 million for NSTAR Electric and $3.1 million for PSNH). See Note 12E, "Commitments and Contingencies – FERC ROE Complaints," for further information on developments in the pending ROE complaint proceedings.

3. PROPERTY, PLANT AND EQUIPMENT AND ACCUMULATED DEPRECIATION

Utility property, plant and equipment is recorded at original cost. Original cost includes materials, labor, construction overheads and AFUDC for regulated property. The cost of repairs and maintenance is charged to Operations and Maintenance expense as incurred.

The following tables summarize property, plant and equipment by asset category:

Eversource	As of December 31,	
(Millions of Dollars)	2018	2017
Distribution - Electric	$ 15,071.1	$ 14,410.5
Distribution - Natural Gas	3,546.2	3,244.2
Transmission - Electric	10,153.9	9,270.9
Distribution - Water	1,639.8	1,558.4
Solar	164.1	36.2
Utility	30,575.1	28,520.2
Other (1)	778.6	693.7
Property, Plant and Equipment, Gross	31,353.7	29,213.9
Less: Accumulated Depreciation		
Utility	(7,126.2)	(6,846.9)
Other	(336.7)	(286.9)
Total Accumulated Depreciation	(7,462.9)	(7,133.8)
Property, Plant and Equipment, Net	23,890.8	22,080.1
Construction Work in Progress	1,719.6	1,537.4
Total Property, Plant and Equipment, Net	$ 25,610.4	$ 23,617.5

	As of December 31,					
	2018			2017		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Distribution - Electric	$ 6,176.4	$ 6,756.4	$ 2,178.6	$ 5,888.3	$ 6,479.0	$ 2,083.4
Transmission - Electric	4,700.5	4,065.9	1,338.7	4,239.9	3,821.2	1,161.3
Solar	—	164.1	—	—	36.2	—
Property, Plant and Equipment, Gross	10,876.9	10,986.4	3,517.3	10,128.2	10,336.4	3,244.7
Less: Accumulated Depreciation	(2,302.6)	(2,702.0)	(772.9)	(2,239.0)	(2,550.2)	(751.8)
Property, Plant and Equipment, Net	8,574.3	8,284.4	2,744.4	7,889.2	7,786.2	2,492.9
Construction Work in Progress	335.4	510.3	135.7	381.8	460.3	149.4
Total Property, Plant and Equipment, Net	$ 8,909.7	$ 8,794.7	$ 2,880.1	$ 8,271.0	$ 8,246.5	$ 2,642.3

(1) These assets are primarily comprised of building improvements, computer software, hardware and equipment at Eversource Service.

Depreciation of utility assets is calculated on a straight-line basis using composite rates based on the estimated remaining useful lives of the various classes of property (estimated useful life for PSNH distribution and the water utilities). The composite rates, which are subject to approval by the appropriate state regulatory agency, include a cost of removal component, which is collected from customers over the lives of the plant assets and is recognized as a regulatory liability. Depreciation rates are applied to property from the time it is placed in service.

Upon retirement from service, the cost of the utility asset is charged to the accumulated provision for depreciation. The actual incurred removal costs are applied against the related regulatory liability.

The depreciation rates for the various classes of utility property, plant and equipment aggregate to composite rates as follows:

(Percent)	2018	2017	2016
Eversource	2.9%	3.0%	3.0%
CL&P	2.8%	2.8%	2.7%
NSTAR Electric	2.8%	2.9%	2.9%
PSNH	2.8%	3.1%	3.1%

The following table summarizes average remaining useful lives of depreciable assets:

	As of December 31, 2018			
(Years)	Eversource	CL&P	NSTAR Electric	PSNH
Distribution - Electric	34.1	35.4	33.7	32.3
Distribution - Natural Gas	43.8	—	—	—
Transmission - Electric	41.3	38.0	45.3	42.9
Distribution - Water	33.3	—	—	—
Solar	24.9	—	24.9	—
Other	12.9	—	—	—

4. DERIVATIVE INSTRUMENTS

The electric and natural gas companies purchase and procure energy and energy-related products, which are subject to price volatility, for their customers. The costs associated with supplying energy to customers are recoverable from customers in future rates. These regulated companies manage the risks associated with the price volatility of energy and energy-related products through the use of derivative and non-derivative contracts.

Many of the derivative contracts meet the definition of, and are designated as, normal and qualify for accrual accounting under the applicable accounting guidance. The costs and benefits of derivative contracts that meet the definition of normal are recognized in Operating Expenses on the statements of income, as applicable, as electricity or natural gas is delivered.

Derivative contracts that are not designated as normal are recorded at fair value as current or long-term Derivative Assets or Derivative Liabilities on the balance sheets. For the electric and natural gas companies, regulatory assets or regulatory liabilities are recorded to offset the fair values of derivatives, as contract settlement amounts are recovered from, or refunded to, customers in their respective energy supply rates.

The gross fair values of derivative assets and liabilities with the same counterparty are offset and reported as net Derivative Assets or Derivative Liabilities, with current and long-term portions, on the balance sheets. The following table presents the gross fair values of contracts, categorized by risk type, and the net amounts recorded as current or long-term derivative assets or liabilities:

		As of December 31,					
		2018			2017		
(Millions of Dollars)	Fair Value Hierarchy	Commodity Supply and Price Risk Management	Netting (1)	Net Amount Recorded as a Derivative	Commodity Supply and Price Risk Management	Netting (1)	Net Amount Recorded as a Derivative
Current Derivative Assets:							
CL&P	Level 3	9.6	(3.4)	6.2	9.5	(7.1)	2.4
Other	Level 2	$ 1.5	$ (0.9)	$ 0.6	$ —	$ —	$ —
Long-Term Derivative Assets:							
CL&P	Level 3	74.2	(2.3)	71.9	71.9	(5.3)	66.6
Current Derivative Liabilities:							
CL&P	Level 3	(55.1)	—	(55.1)	(54.4)	—	(54.4)
Other	Level 2	—	—	—	(4.5)	—	(4.5)
Long-Term Derivative Liabilities:							
CL&P	Level 3	(379.5)	—	(379.5)	(376.9)	—	(376.9)
Other	Level 2	—	—	—	(0.4)	—	(0.4)

(1) Amounts represent derivative assets and liabilities that Eversource elected to record net on the balance sheets. These amounts are subject to master netting agreements or similar agreements for which the right of offset exists.

The business activities that result in the recognition of derivative assets also create exposure to various counterparties. As of December 31, 2018, Eversource's and CL&P's derivative assets were exposed to counterparty credit risk and contracted with investment grade entities.

For further information on the fair value of derivative contracts, see Note 1I, "Summary of Significant Accounting Policies – Fair Value Measurements," and Note 1J, "Summary of Significant Accounting Policies – Derivative Accounting," to the financial statements.

Derivative Contracts at Fair Value with Offsetting Regulatory Amounts

Commodity Supply and Price Risk Management: As required by regulation, CL&P, along with UI, has capacity-related contracts with generation facilities. CL&P has a sharing agreement with UI, with 80 percent of the costs or benefits of each contract borne by or allocated to CL&P and 20 percent borne by or allocated to UI. The combined capacity of these contracts is 787 MW. The capacity contracts extend through 2026 and obligate both CL&P and UI to make or receive payments on a monthly basis to or from the generation facilities based on the difference between a set capacity price and the capacity market price received in the ISO-NE capacity markets. In addition, CL&P has a contract to purchase 0.1 million MWh of energy per year through 2020.

As of December 31, 2018 and 2017, Eversource had New York Mercantile Exchange ("NYMEX") financial contracts for natural gas futures in order to reduce variability associated with the price of 12.5 million and 9.5 million MMBtu of natural gas, respectively.

For the years ended December 31, 2018, 2017 and 2016, there were losses of $25.0 million, $29.0 million and $125.5 million, respectively, deferred as regulatory costs, which reflect the change in fair value associated with Eversource's derivative contracts.

Fair Value Measurements of Derivative Instruments

Derivative contracts classified as Level 2 in the fair value hierarchy relate to the financial contracts for natural gas futures. Prices are obtained from broker quotes and are based on actual market activity. The contracts are valued using NYMEX natural gas prices. Valuations of these contracts also incorporate discount rates using the yield curve approach.

The fair value of derivative contracts classified as Level 3 utilizes significant unobservable inputs. The fair value is modeled using income techniques, such as discounted cash flow valuations adjusted for assumptions related to exit price. Significant observable inputs for valuations of these contracts include energy and energy-related product prices in future years for which quoted prices in an active market exist. Fair value measurements categorized in Level 3 of the fair value hierarchy are prepared by individuals with expertise in valuation techniques, pricing of energy and energy-related products, and accounting requirements. The future power and capacity prices for periods that are not quoted in an active market or established at auction are based on available market data and are escalated based on estimates of inflation in order to address the full term of the contract.

Valuations of derivative contracts using a discounted cash flow methodology include assumptions regarding the timing and likelihood of scheduled payments and also reflect non-performance risk, including credit, using the default probability approach based on the counterparty's credit rating for assets and the Company's credit rating for liabilities. Valuations incorporate estimates of premiums or discounts that would be required by a market participant to arrive at an exit price, using historical market transactions adjusted for the terms of the contract.

The following is a summary of CL&P's Level 3 derivative contracts and the range of the significant unobservable inputs utilized in the valuations over the duration of the contracts:

	As of December 31,									
	2018					2017				
CL&P	Range				Period Covered	Range				Period Covered
Capacity Prices	$ 4.30	—	7.44	per kW-Month	2022 - 2026	$ 5.00	—	8.70	per kW-Month	2021 - 2026
Forward Reserve	0.75	—	1.78	per kW-Month	2019 - 2024	1.00	—	2.00	per kW-Month	2018 - 2024

Exit price premiums of 4.2 percent through 15.7 percent are also applied to these contracts and reflect the uncertainty and illiquidity premiums that would be required based on the most recent market activity available for similar type contracts.

Significant increases or decreases in future capacity or forward reserve prices in isolation would decrease or increase, respectively, the fair value of the derivative liability. Any increases in risk premiums would increase the fair value of the derivative liability. Changes in these fair values are recorded as a regulatory asset or liability and do not impact net income.

Valuations using significant unobservable inputs: The following table presents changes in the Level 3 category of derivative assets and derivative liabilities measured at fair value on a recurring basis. The derivative assets and liabilities are presented on a net basis.

CL&P *(Millions of Dollars)*	For the Years Ended December 31,	
	2018	**2017**
Derivatives, Net:		
Fair Value as of Beginning of Period	$ (362.3)	$ (420.5)
Net Realized/Unrealized Losses Included in Regulatory Assets and Liabilities	(32.0)	(9.5)
Settlements	37.8	67.7
Fair Value as of End of Period	$ (356.5)	$ (362.3)

5. MARKETABLE SECURITIES

Eversource holds marketable securities that are primarily used to fund certain non-qualified executive benefits. The trusts that hold marketable securities are not subject to regulatory oversight by state or federal agencies. CYAPC and YAEC maintain legally restricted trusts, each of which holds marketable securities, to fund the spent nuclear fuel removal obligations of their nuclear fuel storage facilities. In December 2018, CYAPC paid $145 million from its trust to the DOE to partially settle the pre-1983 spent nuclear fuel obligation.

Equity Securities: In accordance with new accounting guidance, unrealized gains and losses on equity securities are recorded in Other Income, Net on the statements of income. The fair value of equity securities subject to this guidance as of December 31, 2018 and 2017 was $44.0 million and $52.5 million, respectively. For the year ended December 31, 2018, there were unrealized losses of $4.3 million recorded in Other Income, Net related to these equity securities. For the year ended December 31, 2017, the unrealized gains and losses on these equity securities were recorded in Accumulated Other Comprehensive Income on the balance sheet. Dividend income is recorded in Other Income, Net when dividends are declared.

Eversource's equity securities also include CYAPC's and YAEC's marketable securities held in spent nuclear fuel trusts, which had fair values of $200.0 million and $261.3 million as of December 31, 2018 and 2017, respectively. Unrealized gains and losses for these spent nuclear fuel trusts are subject to regulatory accounting treatment and are recorded in Marketable Securities with the corresponding offset to Other Long-Term Liabilities on the balance sheets, with no impact on the statements of income.

Available-for-Sale Debt Securities: The following is a summary of the available-for-sale debt securities, which are recorded at fair value and are included in current and long-term Marketable Securities on the balance sheets.

	As of December 31,							
	2018				2017			
Eversource *(Millions of Dollars)*	**Amortized Cost**	**Pre-Tax Unrealized Gains**	**Pre-Tax Unrealized Losses**	**Fair Value**	**Amortized Cost**	**Pre-Tax Unrealized Gains**	**Pre-Tax Unrealized Losses**	**Fair Value**
Debt Securities	$ 190.0	$ 0.4	$ (4.0)	$ 186.4	$ 284.9	$ 3.2	$ (1.1)	$ 287.0

Eversource's debt securities include CYAPC's and YAEC's marketable securities held in spent nuclear fuel trusts in the amounts of $143.9 million and $242.3 million as of December 31, 2018 and 2017, respectively.

Unrealized gains and losses on available-for-sale debt securities held in Eversource's non-qualified benefit trust are recorded in Accumulated Other Comprehensive Income. There have been no significant unrealized losses, other-than-temporary impairments, or credit losses for the years ended December 31, 2018 or 2017. Factors considered in determining whether a credit loss exists include the duration and severity of the impairment, adverse conditions specifically affecting the issuer, and the payment history, ratings and rating changes of the security. For asset-backed debt securities, underlying collateral and expected future cash flows are also evaluated.

As of December 31, 2018, the contractual maturities of available-for-sale debt securities were as follows:

Eversource *(Millions of Dollars)*	**Amortized Cost**	**Fair Value**
Less than one year (1)	$ 30.5	$ 30.3
One to five years	29.2	28.9
Six to ten years	43.6	42.9
Greater than ten years	86.7	84.3
Total Debt Securities	$ 190.0	$ 186.4

(1) Amounts in the Less than one year category include securities in the CYAPC and YAEC spent nuclear fuel trusts, which are restricted and are classified in long-term Marketable Securities on the balance sheets.

Realized Gains and Losses: Realized gains and losses are recorded in Other Income, Net for Eversource's benefit trust and are offset in Other Long-Term Liabilities for CYAPC and YAEC. Eversource utilizes the specific identification basis method for the Eversource non-qualified benefit trust, and the average cost basis method for the CYAPC and YAEC spent nuclear fuel trusts to compute the realized gains and losses on the sale of marketable securities. For the year ended December 31, 2017, Eversource recognized net realized gains of $9.8 million on the sales of available-for-sale securities held in the benefit trust. The proceeds of the sales were re-invested in the Eversource benefit trust. There were no similar sales for the year ended December 31, 2018.

Fair Value Measurements: The following table presents the marketable securities recorded at fair value on a recurring basis by the level in which they are classified within the fair value hierarchy:

Eversource *(Millions of Dollars)*	**As of December 31,**	
	2018	**2017**
Level 1:		
Mutual Funds and Equities	$ 244.0	$ 313.8
Money Market Funds	25.9	23.3
Total Level 1	$ 269.9	$ 337.1
Level 2:		
U.S. Government Issued Debt Securities (Agency and Treasury)	$ 79.6	$ 70.2
Corporate Debt Securities	39.5	50.9
Asset-Backed Debt Securities	14.0	21.2
Municipal Bonds	19.2	110.7
Other Fixed Income Securities	8.2	10.7
Total Level 2	$ 160.5	$ 263.7
Total Marketable Securities	$ 430.4	$ 600.8

U.S. government issued debt securities are valued using market approaches that incorporate transactions for the same or similar bonds and adjustments for yields and maturity dates. Corporate debt securities are valued using a market approach, utilizing recent trades of the same or similar instruments and also incorporating yield curves, credit spreads and specific bond terms and conditions. Asset-backed debt securities include collateralized mortgage obligations, commercial mortgage backed securities, and securities collateralized by auto loans, credit card loans or receivables. Asset-backed debt securities are valued using recent trades of similar instruments, prepayment assumptions, yield curves, issuance and

maturity dates, and tranche information. Municipal bonds are valued using a market approach that incorporates reported trades and benchmark yields. Other fixed income securities are valued using pricing models, quoted prices of securities with similar characteristics, and discounted cash flows.

6. ASSET RETIREMENT OBLIGATIONS

Eversource, including CL&P, NSTAR Electric and PSNH, recognizes a liability for the fair value of an ARO on the obligation date if the liability's fair value can be reasonably estimated, even if it is conditional on a future event. Settlement dates and future costs are reasonably estimated when sufficient information becomes available. Management has identified various categories of AROs, primarily CYAPC's and YAEC's obligation to dispose of spent nuclear fuel and high level waste, and also certain assets containing asbestos and hazardous contamination. Management has performed fair value calculations reflecting expected probabilities for settlement scenarios.

The fair value of an ARO is recorded as a liability in Other Long-Term Liabilities with a corresponding amount included in Property, Plant and Equipment, Net on the balance sheets. The ARO assets are depreciated, and the ARO liabilities are accreted over the estimated life of the obligation and the corresponding credits are recorded as accumulated depreciation and ARO liabilities, respectively. As the electric and natural gas companies are rate-regulated on a cost-of-service basis, these companies apply regulatory accounting guidance and both the depreciation and accretion costs associated with these companies' AROs are recorded as increases to Regulatory Assets on the balance sheets.

A reconciliation of the beginning and ending carrying amounts of ARO liabilities is as follows:

	As of December 31,							
	2018				2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Balance as of Beginning of Year	$ 419.1	$ 31.5	$ 44.6	$ 25.0	$ 426.4	$ 36.0	$ 42.6	$ 23.5
Liabilities Incurred During the Year	11.3	—	11.3	—	0.2	0.1	0.1	—
Liabilities Settled During the Year	(36.6)	—	—	(21.5)	(19.3)	(1.0)	(0.2)	—
Accretion	25.5	2.0	2.2	0.5	26.3	2.3	2.1	1.5
Revisions in Estimated Cash Flows	46.9	—	14.3	—	(14.5)	(5.9)	—	—
Balance as of End of Year	$ 466.2	$ 33.5	$ 72.4	$ 4.0	$ 419.1	$ 31.5	$ 44.6	$ 25.0

Eversource's amounts include CYAPC and YAEC's AROs of $339.9 million and $301.5 million as of December 31, 2018 and 2017, respectively. The fair value of the ARO for CYAPC and YAEC includes uncertainties of the fuel off-load dates related to the DOE's timing of performance regarding its obligation to dispose of the spent nuclear fuel and high level waste and other assumptions, including discount rates. The incremental asset recorded as an offset to the ARO liability was fully depreciated since the plants have no remaining useful life. Any changes in the ARO liability are recorded with a corresponding offset to the related regulatory asset. The assets held in the CYAPC and YAEC spent nuclear fuel trusts are restricted for settling the ARO and all other nuclear fuel storage obligations. For further information on the assets held in the spent nuclear fuel trusts, see Note 5, "Marketable Securities," to the financial statements.

The increase in the ARO balance at NSTAR Electric for the year ended December 31, 2018 was due to the recording of new liabilities associated with new solar sites placed into service and the replacement of certain distribution cables, and revised remediation costs for existing AROs related to asbestos and hazardous contamination. The decrease in the ARO balance at PSNH for the year ended December 31, 2018 was a result of the generation divestiture and the securitization of remaining generation costs. See Note 13, "Generation Asset Sale," to the financial statements for further information on the PSNH generation divestiture.

7. SHORT-TERM DEBT

Short-Term Debt Borrowing Limits: The amount of short-term borrowings that may be incurred by CL&P, NSTAR Electric and NPT is subject to periodic approval by the FERC. Because the NHPUC has jurisdiction over PSNH's short-term debt, PSNH is not currently required to obtain FERC approval for its short-term borrowings. On November 30, 2017, the FERC granted authorization that allows CL&P to issue total short-term borrowings in an aggregate principal amount not to exceed $600 million outstanding at any one time, through December 31, 2019. On November 30, 2017, the FERC granted authorization that allows NSTAR Electric to issue total short-term borrowings in an aggregate principal amount not to exceed $655 million outstanding at any one time, through December 30, 2019. On December 3, 2018, FERC authorized NPT to issue up to an aggregate of $800 million in short-term debt and long-term debt through December 31, 2020.

PSNH is authorized by regulation of the NHPUC to incur short-term borrowings up to 10 percent of net fixed plant plus an additional $60 million until further ordered by the NHPUC. As of December 31, 2018, PSNH's short-term debt authorization under the 10 percent of net fixed plant test plus $60 million totaled approximately $331 million.

CL&P's certificate of incorporation contains preferred stock provisions restricting the amount of unsecured debt that CL&P may incur, including limiting unsecured indebtedness with a maturity of less than 10 years to 10 percent of total capitalization. As of December 31, 2018, CL&P had $758.1 million of unsecured debt capacity available under this authorization.

Yankee Gas and NSTAR Gas are not required to obtain approval from any state or federal authority to incur short-term debt.

Commercial Paper Programs and Credit Agreements: Eversource parent has a $1.45 billion commercial paper program allowing Eversource parent to issue commercial paper as a form of short-term debt. Eversource parent, CL&P, PSNH, NSTAR Gas and Yankee Gas are also parties to a five-year $1.45 billion revolving credit facility. Effective December 10, 2018, the revolving credit facility's termination date was extended for one additional year to December 8, 2023. The revolving credit facility serves to backstop Eversource parent's $1.45 billion commercial paper program.

NSTAR Electric has a $650 million commercial paper program allowing NSTAR Electric to issue commercial paper as a form of short-term debt. NSTAR Electric is also a party to a five-year $650 million revolving credit facility. Effective December 10, 2018, the revolving credit facility's termination date was extended for one additional year to December 8, 2023. The revolving credit facility serves to backstop NSTAR Electric's $650 million commercial paper program.

The amount of borrowings outstanding and available under the commercial paper programs were as follows:

	Borrowings Outstanding as of December 31,		Available Borrowing Capacity as of December 31,		Weighted-Average Interest Rate as of December 31,	
(Millions of Dollars)	2018	2017	2018	2017	2018	2017
Eversource Parent Commercial Paper Program	$ 631.5	$ 979.3	$ 818.5	$ 470.7	2.77%	1.86%
NSTAR Electric Commercial Paper Program	278.5	234.0	371.5	416.0	2.50%	1.55%

There were no borrowings outstanding on either the Eversource parent or NSTAR Electric revolving credit facilities as of December 31, 2018 or 2017. Eversource's water distribution segment has a $100.0 million revolving credit facility, which expires on August 19, 2019, and there were no amounts outstanding as of December 31, 2018 and $76.0 million outstanding as of December 31, 2017.

Amounts outstanding under the commercial paper programs and revolving credit facility are included in Notes Payable and classified in current liabilities on the Eversource and NSTAR Electric balance sheets as all borrowings are outstanding for no more than 364 days at one time. As a result of the Eversource parent long-term debt issuances on January 8, 2018, the net proceeds of which were used to repay short-term borrowings outstanding under its commercial paper program, $201.2 million of commercial paper borrowings under the Eversource parent commercial paper program were reclassified as Long-Term Debt as of December 31, 2017.

Under the credit facilities described above, Eversource and its subsidiaries must comply with certain financial and non-financial covenants, including a consolidated debt to total capitalization ratio. As of December 31, 2018 and 2017, Eversource and its subsidiaries were in compliance with these covenants. If Eversource or its subsidiaries were not in compliance with these covenants, an event of default would occur requiring all outstanding borrowings by such borrower to be repaid, and additional borrowings by such borrower would not be permitted under its respective credit facility.

We believe the future operating cash flows of Eversource, CL&P, NSTAR Electric and PSNH, along with our existing borrowing availability and access to financial markets for the issuance of new long-term debt, will be sufficient to meet any working capital and future operating requirements, and capital investment forecast opportunities.

Intercompany Borrowings: Eversource parent uses its available capital resources to provide loans to its subsidiaries to assist in meeting their short-term borrowing needs. In addition, growth in Eversource's key business initiatives requires cash infusion to those subsidiaries. Eversource parent records intercompany interest income from its loans to subsidiaries, which is eliminated in consolidation. Intercompany loans from Eversource parent to its subsidiaries are eliminated in consolidation on Eversource's balance sheets. As of December 31, 2018, there were intercompany loans from Eversource parent to PSNH of $57.0 million. As of December 31, 2017, there were intercompany loans from Eversource parent of $69.5 million to CL&P and $262.9 million to PSNH. Intercompany loans from Eversource parent are included in Notes Payable to Eversource Parent and are classified in current liabilities on the respective subsidiary's balance sheets.

8. LONG-TERM DEBT

Details of long-term debt outstanding are as follows:

CL&P *(Millions of Dollars)*	**As of December 31,**	
	2018	**2017**
First Mortgage Bonds:		
7.875% 1994 Series D due 2024	$ 139.8	$ 139.8
5.750% 2004 Series B due 2034	130.0	130.0
5.625% 2005 Series B due 2035	100.0	100.0
6.350% 2006 Series A due 2036	250.0	250.0
5.750% 2007 Series B due 2037	150.0	150.0
6.375% 2007 Series D due 2037	100.0	100.0
5.650% 2008 Series A due 2018	—	300.0
5.500% 2009 Series A due 2019	250.0	250.0
2.500% 2013 Series A due 2023	400.0	400.0
4.300% 2014 Series A due 2044	475.0	475.0
4.150% 2015 Series A due 2045	350.0	350.0
3.200% 2017 Series A due 2027	300.0	300.0
4.000% 2018 Series A due 2048	500.0	—
Total First Mortgage Bonds	3,144.8	2,944.8
Pollution Control Revenue Bonds:		
4.375% Fixed Rate Tax Exempt due 2028	120.5	120.5
Less Amounts due Within One Year	(250.0)	(300.0)
Unamortized Premiums and Discounts, Net	10.2	11.5
Unamortized Debt Issuance Costs	(21.5)	(17.7)
CL&P Long-Term Debt	$ 3,004.0	$ 2,759.1

NSTAR Electric *(Millions of Dollars)*

	As of December 31, 2018	As of December 31, 2017
Debentures:		
5.750% due 2036	$ 200.0	$ 200.0
5.500% due 2040	300.0	300.0
2.375% due 2022	400.0	400.0
4.400% due 2044	300.0	300.0
3.250% due 2025	250.0	250.0
2.700% due 2026	250.0	250.0
3.200% due 2027	700.0	700.0
Total Debentures	2,400.0	2,400.0
Notes:		
5.900% Senior Notes Series B due 2034	50.0	50.0
6.700% Senior Notes Series D due 2037	40.0	40.0
5.100% Senior Notes Series E due 2020	95.0	95.0
3.500% Senior Notes Series F due 2021	250.0	250.0
3.880% Senior Notes Series G due 2023	80.0	80.0
2.750% Senior Notes Series H due 2026	50.0	50.0
Total Notes	565.0	565.0
Less Amounts due Within One Year	—	—
Unamortized Premiums and Discounts, Net	(2.5)	(1.8)
Unamortized Debt Issuance Costs	(17.7)	(19.4)
NSTAR Electric Long-Term Debt	$ 2,944.8	$ 2,943.8

PSNH *(Millions of Dollars)*

	As of December 31, 2018	As of December 31, 2017
First Mortgage Bonds:		
5.600% Series M due 2035	$ 50.0	$ 50.0
6.000% Series O due 2018	—	110.0
4.500% Series P due 2019	150.0	150.0
4.050% Series Q due 2021	122.0	122.0
3.200% Series R due 2021	160.0	160.0
3.500% Series S due 2023	325.0	325.0
Total First Mortgage Bonds	807.0	917.0
Pollution Control Revenue Bonds:		
Adjustable Rate Tax Exempt Series A due 2021	—	89.3
Less Amounts due Within One Year	(150.0)	(110.0)
Unamortized Premiums and Discounts, Net	—	0.2
Unamortized Debt Issuance Costs	(1.8)	(4.1)
PSNH Long-Term Debt	$ 655.2	$ 892.4

OTHER *(Millions of Dollars)*

	As of December 31, 2018	As of December 31, 2017
Yankee Gas - First Mortgage Bonds: 3.020% - 8.480% due 2019 - 2048	$ 470.0	$ 520.0
NSTAR Gas - First Mortgage Bonds: 4.09% - 9.950% due 2020 - 2048	385.0	285.0
Eversource Parent and Other - Notes and Debentures:		
4.500% Debentures due 2019	350.0	350.0
2.500% - 4.250% Senior Notes due 2021 - 2029	4,360.0	3,260.0
Unsecured Notes 3.570% - 6.430% due 2021 - 2037	289.5	290.9
Secured Debt 4.100% - 9.640% due 2021 - 2035	70.7	70.4
Pre-1983 Spent Nuclear Fuel Obligation (CYAPC)	39.5	181.4
Fair Value Adjustment (1)	144.7	172.6
Less Fair Value Adjustment - Current Portion (1)	(36.2)	(35.4)
Less Amounts due in One Year	(401.1)	(104.2)
Commercial Paper Classified as Long-Term Debt	—	201.2
Unamortized Premiums and Discounts, Net	(4.2)	1.5
Unamortized Debt Issuance Costs	(23.2)	(12.8)
Total Other Long-Term Debt	$ 5,644.7	$ 5,180.6
Total Eversource Long-Term Debt	$ 12,248.7	$ 11,775.9

(1) The fair value adjustment amount is the purchase price adjustments, net of amortization, required to record the NSTAR long-term debt at fair value on the date of the 2012 merger and to record the Aquarion long-term debt at fair value on the date of the 2017 acquisition.

Long-Term Debt Issuances and Repayments: The following table summarizes long-term debt issuances and repayments:

(Millions of Dollars)	Issue Date	Issuances/(Repayments)	Maturity Date	Use of Proceeds for Issuances/ Repayment Information
CL&P:				
4.00% 2018 Series A First Mortgage Bonds	March 2018	$ 500.0	April 2048	Repaid long-term debt that matured in 2018 and repaid short-term borrowings
5.65% 2008 Series A First Mortgage Bonds	May 2008	(300.0)	May 2018	Repaid at maturity on May 1, 2018
PSNH:				
6.00% 2008 Series O First Mortgage Bonds	May 2008	(110.0)	May 2018	Repaid at maturity on May 1, 2018
2001 Series A Pollution Control Revenue Bonds	December 2001	(89.3)	May 2021	Redeemed on November 28, 2018 at a redemption price of $89.3 million
Other:				
Eversource Parent 2.50% Series I Senior Notes (1)	January 2018	200.0	March 2021	Repaid short-term borrowings
Eversource Parent 3.30% Series M Senior Notes	January 2018	450.0	January 2028	Repaid long-term debt that matured in 2018
Eversource Parent 3.80% Series N Senior Notes	December 2018	400.0	December 2023	Repaid short-term borrowings
Eversource Parent 4.25% Series O Senior Notes	December 2018	500.0	April 2029	Repaid short-term borrowings
Eversource Parent 1.60% Series G Senior Notes	January 2015	(150.0)	January 2018	Repaid at maturity on January 15, 2018
Eversource Parent 1.45% Series E Senior Notes	May 2013	(300.0)	May 2018	Repaid at maturity on May 1, 2018
Yankee Gas 4.13% Series O First Mortgage Bonds	September 2018	50.0	October 2048	Repaid long-term debt that matured in 2018
Yankee Gas 6.90% Series J First Mortgage Bonds	October 2008	(100.0)	October 2018	Repaid at maturity on October 1, 2018
NSTAR Gas 4.09% Series P First Mortgage Bonds	September 2018	100.0	October 2048	Repaid short-term borrowings

(1) These notes are part of the same series issued by Eversource parent in March 2016. The aggregate outstanding principal amount of these notes is now $450 million.

As a result of the Eversource parent debt issuances in January 2018, $446.8 million of current portion of long-term debt related to two Eversource parent issuances maturing in 2018 and $201.2 million of commercial paper borrowings were reclassified to Long-Term Debt as of December 31, 2017.

Long-Term Debt Issuance Authorizations: On August 1, 2018, the DPU approved NSTAR Gas' request for authorization to issue up to $200 million in long-term debt through December 31, 2019. On December 3, 2018, FERC authorized NPT to issue up to an aggregate of $800 million in short-term debt and long-term debt through December 31, 2020.

Long-Term Debt Provisions: The utility plant of CL&P, PSNH, Yankee Gas, NSTAR Gas and a portion of Aquarion is subject to the lien of each company's respective first mortgage bond indenture. The Eversource parent, NSTAR Electric and certain Aquarion debt is unsecured. Additionally, the long-term debt agreements provide that Eversource and certain of its subsidiaries must comply with certain covenants as are customarily included in such agreements, including equity requirements for NSTAR Electric and NSTAR Gas. Under the equity requirements, NSTAR Electric's and Aquarion's senior notes must maintain a certain consolidated indebtedness to capitalization ratio as of the end of any fiscal quarter and NSTAR Gas' outstanding long-term debt must not exceed equity.

CL&P's obligation to repay the PCRBs is secured by first mortgage bonds. The first mortgage bonds contain similar terms and provisions as the applicable series of PCRBs. If CL&P fails to meet its obligations under the first mortgage bonds, then the holder of the first mortgage bonds (the issuer of the PCRBs) would have rights under the first mortgage bonds. CL&P's tax-exempt PCRBs will be subject to redemption at par on or after September 1, 2021.

Certain secured and unsecured long-term debt securities are callable at redemption price or are subject to make-whole provisions.

Eversource, NSTAR Electric, Yankee Gas and Aquarion have certain long-term debt agreements that contain cross-default provisions. No other debt issuances contain cross-default provisions as of December 31, 2018.

Pre-1983 Spent Nuclear Fuel Obligation: Under the Nuclear Waste Policy Act of 1982, the DOE is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste. CYAPC is obligated to pay the DOE for the costs to dispose of spent nuclear fuel and high-level radioactive waste generated prior to April 7, 1983 (pre-1983 Spent Nuclear Fuel) and recorded an accrual for the full liability thereof to the DOE. This liability accrues interest costs at the 3-month Treasury bill yield rate. For nuclear fuel used to generate electricity prior to April 7, 1983, payment may be made any time prior to the first delivery of spent fuel to the DOE. Fees for disposal of nuclear fuel burned on or after April 7, 1983 were billed to member companies and paid to the DOE.

As of December 31, 2018 and 2017, as a result of consolidating CYAPC, Eversource has consolidated $39.5 million and $181.4 million, respectively, in pre-1983 spent nuclear fuel obligations to the DOE. In December 2018, CYAPC paid $145 million to the DOE to partially settle this obligation. The obligation includes accumulated interest costs of $29.0 million and $132.6 million as of December 31, 2018 and 2017, respectively. CYAPC maintains a trust to fund amounts due to the DOE for the disposal of pre-1983 spent nuclear fuel. For further information, see Note 5, "Marketable Securities," to the financial statements.

Long-Term Debt Maturities: Long-term debt maturities on debt outstanding for the years 2019 through 2023 and thereafter are shown below. These amounts exclude the CYAPC pre-1983 spent nuclear fuel obligation, net unamortized premiums, discounts and debt issuance costs, and other fair value adjustments as of December 31, 2018:

(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
2019	$ 801.1	$ 250.0	$ —	$ 150.0
2020	296.1	—	95.0	—
2021	1,033.5	—	250.0	282.0
2022	1,188.9	—	400.0	—
2023	1,665.2	400.0	80.0	325.0
Thereafter	7,977.7	2,615.3	2,140.0	50.0
Total	$ 12,962.5	$ 3,265.3	$ 2,965.0	$ 807.0

9. RATE REDUCTION BONDS AND VARIABLE INTEREST ENTITIES

Rate Reduction Bonds: PSNH Funding LLC 3 (PSNH Funding) is a bankruptcy remote, special purpose, wholly-owned subsidiary of PSNH. PSNH Funding was formed solely to issue rate reduction bonds (RRBs) to finance PSNH's unrecovered remaining costs associated with the divestiture of its generation assets.

On May 8, 2018, PSNH Funding issued $635.7 million of securitized RRBs in multiple tranches with a weighted average interest rate of 3.66 percent, and final maturity dates ranging from 2026 to 2035. The RRBs are expected to be repaid by February 1, 2033. RRB payments consist of principal and interest and will be paid semi-annually, beginning on February 1, 2019. The RRBs were issued pursuant to a finance order issued by the NHPUC on January 30, 2018 to recover remaining costs resulting from the divestiture of PSNH's generation assets.

The proceeds were used by PSNH Funding to purchase PSNH's stranded cost asset-recovery property, including its vested property right to bill, collect and adjust a non-bypassable stranded cost recovery charge from PSNH's retail customers. The collections will be used to pay principal, interest and other costs in connection with the RRBs. The RRBs are secured by the stranded cost asset-recovery property. Cash collections from the stranded cost recovery charges and funds on deposit in trust accounts are the sole source of funds to satisfy the debt obligation. PSNH is not the owner of the RRBs, and PSNH Funding's assets and revenues are not available to pay PSNH's creditors. The RRBs are non-recourse senior secured obligations of PSNH Funding and are not insured or guaranteed by PSNH or Eversource Energy.

PSNH Funding is considered a variable interest entity (VIE) primarily because the equity capitalization is insufficient to support its operations. PSNH has the power to direct the significant activities of the VIE and is most closely associated with the VIE as compared to other interest holders. Therefore, PSNH is considered the primary beneficiary and consolidates PSNH Funding in its consolidated financial statements. The following tables summarize the impact of PSNH Funding on PSNH's balance sheet and income statement:

(Millions of Dollars)

Balance Sheet:	As of December 31, 2018
Restricted Cash - Current Portion (included in Prepayments and Other Current Assets)	$ 47.5
Restricted Cash - Long-Term Portion (included in Other Long-Term Assets)	3.2
Securitized Stranded Cost (included in Regulatory Assets)	608.4
Other Regulatory Liabilities (included in Regulatory Liabilities)	5.8
Accrued Interest (included in Other Current Liabilities)	14.4
Rate Reduction Bonds - Current Portion	52.3
Rate Reduction Bonds - Long-Term Portion	583.3

(Millions of Dollars)

Income Statement:	For the Year Ended December 31, 2018
Amortization of RRB Principal (included in Amortization of Regulatory Assets, Net)	$ 27.3
Interest Expense on RRB Principal (included in Interest Expense)	14.4

Variable Interest Entities - Other: The Company's variable interests outside of the consolidated group include contracts that are required by regulation and provide for regulatory recovery of contract costs and benefits through customer rates. Eversource, CL&P and NSTAR Electric hold variable interests in VIEs through agreements with certain entities that own single renewable energy or peaking generation power plants, with other independent power producers and with transmission businesses. Eversource, CL&P and NSTAR Electric do not control the activities that are economically significant to these VIEs or provide financial or other support to these VIEs. Therefore, Eversource, CL&P and NSTAR Electric do not consolidate these VIEs.

10. EMPLOYEE BENEFITS

A. Pension Benefits and Postretirement Benefits Other Than Pension

Eversource provides defined benefit retirement plans ("Pension Plans") that cover eligible employees and are subject to the provisions of ERISA, as amended by the PPA of 2006. Eversource's policy is to annually fund the Pension Plans in an amount at least equal to an amount that will satisfy all federal funding requirements. In addition to the Pension Plans, Eversource maintains non-qualified defined benefit retirement plans ("SERP Plans") which provide benefits in excess of Internal Revenue Code limitations to eligible participants consisting of current and retired employees.

Eversource also provides defined benefit postretirement plans ("PBOP Plans") that provide life insurance and a health reimbursement arrangement created for the purpose of reimbursing retirees and dependents for health insurance premiums and certain medical expenses to eligible employees that met certain age and service eligibility requirements. The benefits provided under the PBOP Plans are not vested, and the Company has the right to modify any benefit provision subject to applicable laws at that time. Eversource annually funds postretirement costs through tax deductible contributions to external trusts.

The Pension, SERP and PBOP Plans cover eligible employees, including, among others, employees of the regulated companies. Because the regulated companies recover retiree benefit costs from customers through rates, regulatory assets are recorded in lieu of recording an adjustment to Accumulated Other Comprehensive Income/(Loss) for the funded status of the Pension, SERP and PBOP Plans. Regulatory accounting is also applied to the portions of the Eversource Service retiree benefit costs that support the regulated companies, as these costs are also recovered from customers. Adjustments to the Pension and PBOP Plans funded status for the unregulated companies are recorded on an after-tax basis to Accumulated Other Comprehensive Income/(Loss). For further information, see Note 2, "Regulatory Accounting," and Note 16, "Accumulated Other Comprehensive Income/(Loss)," to the financial statements.

The difference between the actual return and calculated expected return on plan assets for the Pension and PBOP Plans is reflected as a component of unamortized actuarial gains or losses, which are recorded in Regulatory Assets or Accumulated Other Comprehensive Income/(Loss). Unamortized actuarial gains or losses are amortized as a component of pension and PBOP expense over the estimated average future employee service period.

Pension and SERP Plans: The Pension and SERP Plans are accounted for under the multiple-employer approach, with each operating company's balance sheet reflecting its share of the funded status of the plans. Although Eversource maintains marketable securities in a benefit trust, the SERP Plans do not contain any assets. For further information, see Note 5, "Marketable Securities," to the financial statements. The following table provides information on the Pension and SERP Plan benefit obligations, fair values of Pension Plan assets, and funded status:

	Pension and SERP							
	As of December 31, 2018				As of December 31, 2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Change in Benefit Obligation:								
Benefit Obligation as of Beginning of Year	$ (5,936.5)	$ (1,275.2)	$ (1,351.0)	$ (642.2)	$ (5,242.3)	$ (1,170.2)	$ (1,217.3)	$ (572.2)
Service Cost	(84.8)	(21.4)	(17.4)	(11.2)	(71.3)	(18.5)	(15.5)	(9.7)
Interest Cost	(196.4)	(41.8)	(43.5)	(22.0)	(188.0)	(41.6)	(42.7)	(21.2)
Actuarial Gain/(Loss)	414.9	106.1	98.6	39.2	(548.7)	(116.9)	(143.5)	(65.1)
Benefits Paid - Pension	261.8	59.6	66.9	26.2	243.7	63.5	55.4	26.4
Benefits Paid - Lump Sum	14.2	—	7.1	—	18.4	—	6.8	—
Benefits Paid - SERP	6.8	0.3	0.3	0.2	20.4	0.3	0.3	0.3
Employee Transfers	—	12.0	2.5	(0.9)	—	8.2	5.5	(0.7)
Increase due to acquisition of Aquarion	—	—	—	—	(168.7)	—	—	—
Benefit Obligation as of End of Year	$ (5,520.0)	$ (1,160.4)	$ (1,236.5)	$ (610.7)	$ (5,936.5)	$ (1,275.2)	$ (1,351.0)	$ (642.2)
Change in Pension Plan Assets:								
Fair Value of Pension Plan Assets as of Beginning of Year	$ 4,739.5	$ 963.0	$ 1,260.8	$ 539.5	$ 4,076.0	$ 905.5	$ 1,088.3	$ 494.0
Employer Contributions	185.6	41.2	56.5	—	235.2	2.5	85.4	0.8
Actual Return on Pension Plan Assets	(75.2)	(14.2)	(18.7)	(7.6)	589.7	126.7	154.8	70.4
Benefits Paid - Pension	(261.8)	(59.6)	(66.9)	(26.2)	(243.7)	(63.5)	(55.4)	(26.4)
Benefits Paid - Lump Sum	(14.2)	—	(7.1)	—	(18.4)	—	(6.8)	—
Employee Transfers	—	(12.0)	(2.5)	0.9	—	(8.2)	(5.5)	0.7
Increase due to acquisition of Aquarion	—	—	—	—	100.7	—	—	—
Fair Value of Pension Plan Assets as of End of Year	$ 4,573.9	$ 918.4	$ 1,222.1	$ 506.6	$ 4,739.5	$ 963.0	$ 1,260.8	$ 539.5
Funded Status as of December 31st	$ (946.1)	$ (242.0)	$ (14.4)	$ (104.1)	$ (1,197.0)	$ (312.2)	$ (90.2)	$ (102.7)

In 2018, there was an increase to the discount rate used to calculate the funded status of the Eversource pension liability, which resulted in a decrease to Eversource's pension liability of approximately $465 million as of December 31, 2018, which was partially offset by changes in actual plan experience and changes in other assumptions.

In 2017, there was a decrease to the discount rate used to calculate the funded status of the Eversource pension liability, which resulted in an increase to Eversource's pension liability of approximately $390 million as of December 31, 2017.

The pension and SERP Plans' funded status includes the current portion of the SERP liability totaling $8.9 million and $8.4 million as of December 31, 2018 and 2017, respectively, which is included in Other Current Liabilities on the balance sheets.

As of December 31, 2018 and 2017, the accumulated benefit obligation for the Pension and SERP Plans is as follows:

(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
2018	$ 5,070.8	$ 1,031.0	$ 1,144.7	$ 543.1
2017	5,583.6	1,179.2	1,260.1	597.2

The following actuarial assumptions were used in calculating the Pension and SERP Plans' year end funded status:

	Pension and SERP	
	As of December 31,	
	2018	2017
Discount Rate	4.22% — 4.45%	3.43% — 3.75%
Compensation/Progression Rate	3.50%	3.50%

The compensation rate for the Aquarion Plans was 4 percent as of December 31, 2018 and 2017.

Pension and SERP Expense: Eversource charges net periodic pension expense to its subsidiaries based on the actual participant demographic data for each subsidiary's participants. The actual investment return in the trust is allocated to each of the subsidiaries annually in proportion to the investment return expected to be earned during the year. The Company utilizes the spot rate methodology to estimate the discount rate for the service and interest cost components of pension expense, which provides a more precise measurement by matching projected cash flows to the corresponding spot rates on the yield curve.

The components of net periodic benefit expense for the Pension and SERP Plans, prior to amounts capitalized as Property, Plant and Equipment or deferred as regulatory assets for future recovery, are shown below. The service cost component of net periodic benefit expense and the intercompany allocations, less the capitalized portions, are included in Operations and Maintenance expense on the statements of income. The remaining components of net periodic benefit costs are included in Other Income, Net on the statements of income. Pension and SERP expense reflected in the statements of cash flows for CL&P, NSTAR Electric and PSNH does not include the intercompany allocations or the corresponding capitalized and deferred portion, as these amounts are cash settled on a short-term basis.

	Pension and SERP			
	For the Year Ended December 31, 2018			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
Service Cost	$ 84.8	$ 21.4	$ 17.4	$ 11.2
Interest Cost	196.4	41.8	43.5	22.0
Expected Return on Pension Plan Assets	(391.6)	(79.1)	(104.9)	(43.6)
Actuarial Loss	145.7	29.1	41.1	11.6
Prior Service Cost	4.3	1.1	0.2	0.4
Total Net Periodic Benefit Expense/(Income)	$ 39.6	$ 14.3	$ (2.7)	$ 1.6
Intercompany Allocations	N/A	$ 6.1	$ 6.5	$ 1.9

	Pension and SERP			
	For the Year Ended December 31, 2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
Service Cost	$ 71.3	$ 18.5	$ 15.5	$ 9.7
Interest Cost	188.0	41.6	42.7	21.2
Expected Return on Pension Plan Assets	(334.1)	(71.7)	(87.6)	(40.0)
Actuarial Loss	135.2	27.7	41.1	11.6
Prior Service Cost	4.5	1.5	0.6	0.5
Total Net Periodic Benefit Expense	$ 64.9	$ 17.6	$ 12.3	$ 3.0
Intercompany Allocations	N/A	$ 9.8	$ 9.1	$ 3.3

	Pension and SERP			
	For the Year Ended December 31, 2016			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
Service Cost	$ 75.0	$ 18.8	$ 16.3	$ 9.9
Interest Cost	185.5	41.6	42.2	20.7
Expected Return on Pension Plan Assets	(317.9)	(72.1)	(85.1)	(38.6)
Actuarial Loss	125.7	25.4	39.9	9.9
Prior Service Cost	3.6	1.5	0.3	0.5
Total Net Periodic Benefit Expense	$ 71.9	$ 15.2	$ 13.6	$ 2.4
Intercompany Allocations	N/A	$ 13.8	$ 11.4	$ 4.0

The following actuarial assumptions were used to calculate Pension and SERP expense amounts:

	Pension and SERP		
	For the Years Ended December 31,		
	2018	2017	2016
Discount Rate	3.85% — 4.62%	3.20% — 3.90%	3.27% — 4.89%
Expected Long-Term Rate of Return	8.25%	8.25%	8.25%
Compensation/Progression Rate	3.50%	3.50%	3.50%

For the Aquarion Plans, the long-term expected rate of return was 7 percent and the compensation rate was 4 percent for the year ended December 31, 2018.

The following is a summary of the changes in plan assets and benefit obligations recognized in Regulatory Assets and Other Comprehensive Income ("OCI") as well as amounts in Regulatory Assets and OCI that were reclassified as net periodic benefit expense during the years presented:

	Regulatory Assets		OCI	
	For the Years Ended December 31,		For the Years Ended December 31,	
(Millions of Dollars)	2018	2017	2018	2017
Actuarial Losses Arising During the Year	$ 48.6	$ 333.0	$ 0.7	$ 9.3
Actuarial Losses Reclassified as Net Periodic Benefit Expense	(140.1)	(129.5)	(5.6)	(5.7)
Actuarial Losses Securitized as Stranded Costs (1)	(36.7)	—	—	—
Prior Service Cost/(Credit) Arising During the Year	—	1.0	—	(0.4)
Prior Service Cost Reclassified as Net Periodic Benefit Expense	(3.9)	(4.1)	(0.4)	(0.4)
Prior Service Cost Securitized as Stranded Costs (1)	(0.1)	—	—	—

(1) These amounts were reclassified to securitized regulatory assets in connection with the divestiture of PSNH's generation business. For further information see Note 2, "Regulatory Accounting" to the financial statements.

The following is a summary of the remaining Regulatory Assets and Accumulated Other Comprehensive Income amounts that have not been recognized as components of net periodic benefit expense as of December 31, 2018 and 2017, as well as the amounts that are expected to be recognized as components in 2019:

	Regulatory Assets as of December 31,		Expected 2019 Expense	AOCI as of December 31,		Expected 2019 Expense
(Millions of Dollars)	2018	2017		2018	2017	
Actuarial Loss	$ 1,807.6	$ 1,935.8	$ 140.6	$ 80.8	$ 85.7	$ 5.6
Prior Service Cost	6.3	10.3	0.9	1.1	1.5	0.2

PBOP Plans: The PBOP Plans are accounted for under the multiple-employer approach, with each operating company's balance sheet reflecting its share of the funded status of the plans. The following table provides information on the PBOP Plan benefit obligations, fair values of plan assets, and funded status:

	PBOP							
	As of December 31,							
	2018				2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Change in Benefit Obligation:								
Benefit Obligation as of Beginning of Year	$ (948.6)	$ (178.4)	$ (278.6)	$ (101.1)	$ (810.0)	$ (165.0)	$ (270.0)	$ (89.7)
Service Cost	(10.0)	(1.9)	(2.0)	(1.1)	(9.5)	(1.9)	(1.7)	(1.3)
Interest Cost	(30.7)	(5.8)	(8.7)	(3.4)	(27.1)	(5.3)	(8.7)	(3.0)
Actuarial Gain/(Loss)	102.5	14.4	28.4	8.6	(81.8)	(18.5)	(13.2)	(11.9)
Benefits Paid	45.3	10.1	14.5	4.9	41.5	9.9	13.5	4.6
Employee Transfers	—	(0.1)	0.1	0.2	—	2.4	1.5	0.2
Increase due to acquisition of Aquarion	—	—	—	—	(61.7)	—	—	—
Benefit Obligation as of End of Year	$ (841.5)	$ (161.7)	$ (246.3)	$ (91.9)	$ (948.6)	$ (178.4)	$ (278.6)	$ (101.1)
Change in Plan Assets:								
Fair Value of Plan Assets as of Beginning of Year	$ 922.2	$ 135.9	$ 405.5	$ 79.0	$ 815.8	$ 129.2	$ 361.6	$ 73.2
Actual Return on Plan Assets	(36.6)	(5.2)	(17.4)	(2.9)	118.0	18.1	52.9	10.4
Employer Contributions	9.3	—	5.2	—	7.6	—	5.3	—
Benefits Paid	(45.3)	(10.1)	(14.5)	(4.9)	(41.5)	(9.9)	(13.5)	(4.6)
Employee Transfers	—	—	0.3	—	—	(1.5)	(0.8)	—
Increase due to acquisition of Aquarion	—	—	—	—	22.3	—	—	—
Fair Value of Plan Assets as of End of Year	$ 849.6	$ 120.6	$ 379.1	$ 71.2	$ 922.2	$ 135.9	$ 405.5	$ 79.0
Funded Status as of December 31st	$ 8.1	$ (41.1)	$ 132.8	$ (20.7)	$ (26.4)	$ (42.5)	$ 126.9	$ (22.1)

The Eversource funded status includes prepaid assets of $33.4 million and $13.1 million recorded in Other Long-Term Assets and liabilities of $25.3 million and $39.5 million included in Accrued Pension, SERP and PBOP on the balance sheets as of December 31, 2018 and 2017, respectively.

As of December 31, 2018, there was an increase in the discount rate used to calculate the funded status, resulting in a decrease in the Eversource PBOP liability of approximately $88 million.

As of December 31, 2017, there was a decrease in the discount rate used to calculate the funded status, as compared to the discount rate as of December 31, 2016, resulting in an increase to the Eversource PBOP liability of approximately $64 million.

The following actuarial assumptions were used in calculating the PBOP Plans' year end funded status:

	PBOP					
	As of December 31,					
	2018			2017		
Discount Rate	4.38%	—	4.41%	3.55%	—	3.70%

For the Eversource Service PBOP Plan, effective with the plan amendment that standardized plan designs and made benefit changes in August 2016, the health care cost trend rate is no longer applicable. For the Aquarion PBOP Plan, the health care trend rate is a range of 3.5 percent to 6.75 percent, with an ultimate rate of 3.5 percent to 5 percent in 2019 and 2023, for post-65 and pre-65 retirees, respectively.

PBOP Expense: Eversource charges net periodic postretirement benefits expense to its subsidiaries based on the actual participant demographic data for each subsidiary's participants. The actual investment return in the trust each year is allocated to each of the subsidiaries annually in proportion to the investment return expected to be earned during the year. The Company utilizes the spot rate methodology to estimate the discount rate for the service and interest cost components of PBOP expense, which provides a more precise measurement by matching projected cash flows to the corresponding spot rates on the yield curve.

The components of net periodic benefit expense for the PBOP Plans, prior to amounts capitalized as Property, Plant and Equipment or deferred as regulatory assets on the balance sheets, are shown below. The service cost component of net periodic benefit expense and the intercompany allocations, less the capitalized portions, are included in Operations and Maintenance expense on the statements of income. The remaining components of net periodic benefit costs are included in Other Income, Net on the statements of income. PBOP expense reflected in the statements of cash flows for CL&P, NSTAR Electric and PSNH does not include the intercompany allocations or the corresponding capitalized portion, as these amounts are cash settled on a short-term basis.

	PBOP			
	For the Year Ended December 31, 2018			
(Millions of Dollars)	**Eversource**	**CL&P**	**NSTAR Electric**	**PSNH**
Service Cost	$ 10.0	$ 1.9	$ 2.0	$ 1.1
Interest Cost	30.7	5.8	8.7	3.4
Expected Return on Plan Assets	(72.4)	(10.4)	(32.5)	(6.0)
Actuarial Loss	10.3	1.6	2.3	0.7
Prior Service (Credit)/Cost	(23.6)	1.1	(16.9)	0.5
Total Net Periodic Benefit Income	$ (45.0)	$ —	$ (36.4)	$ (0.3)
Intercompany Allocations	N/A	$ (1.0)	$ (1.3)	$ (0.4)

	PBOP			
	For the Year Ended December 31, 2017			
(Millions of Dollars)	**Eversource**	**CL&P**	**NSTAR Electric**	**PSNH**
Service Cost	$ 9.5	$ 1.9	$ 1.7	$ 1.3
Interest Cost	27.1	5.3	8.7	3.0
Expected Return on Plan Assets	(63.7)	(9.7)	(28.6)	(5.5)
Actuarial Loss	9.1	1.0	3.4	0.6
Prior Service (Credit)/Cost	(21.6)	1.1	(17.0)	0.6
Total Net Periodic Benefit Income	$ (39.6)	$ (0.4)	$ (31.8)	$ —
Intercompany Allocations	N/A	$ (0.7)	$ (1.1)	$ (0.5)

	PBOP			
	For the Year Ended December 31, 2016			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
Service Cost	$ 12.2	$ 2.0	$ 3.4	$ 1.3
Interest Cost	32.9	5.3	13.3	2.9
Expected Return on Plan Assets	(62.9)	(10.1)	(28.1)	(5.5)
Actuarial Loss	9.0	1.5	3.3	0.7
Prior Service (Credit)/Cost	(9.1)	0.5	(7.1)	0.2
Total Net Periodic Benefit Income	$ (17.9)	$ (0.8)	$ (15.2)	$ (0.4)
Intercompany Allocations	N/A	$ 0.3	$ (0.1)	$ (0.1)

The following actuarial assumptions were used to calculate PBOP expense amounts:

	PBOP		
	For the Years Ended December 31,		
	2018	2017	2016
Discount Rate	3.28% — 3.94%	3.48% — 4.64%	2.88% — 4.09%
Expected Long-Term Rate of Return	8.25%	8.25%	8.25%

For the Aquarion Plan, the expected long-term rate of return was 7 percent and the health care trend rate was 7 percent for the year ended December 31, 2018.

The following is a summary of the changes in plan assets and benefit obligations recognized in Regulatory Assets and OCI as well as amounts recognized in Regulatory Assets and OCI that were reclassified as net periodic benefit (expense)/income during the years presented:

	Regulatory Assets		OCI	
	For the Years Ended December 31,		For the Years Ended December 31,	
(Millions of Dollars)	2018	2017	2018	2017
Actuarial Losses/(Gains) Arising During the Year	$ 6.4	$ 44.8	$ (1.2)	$ 2.6
Actuarial Losses Reclassified as Net Periodic Benefit Expense	(9.9)	(8.6)	(0.4)	(0.5)
Actuarial Losses Securitized as Stranded Costs (1)	(0.8)	—	—	—
Prior Service (Credit)/Cost Arising During the Year	1.3	(4.0)	—	(0.1)
Prior Service Credit/(Cost) Reclassified as Net Periodic Benefit Income/(Expense)	23.6	22.3	—	(0.7)
Prior Service Cost Securitized as Stranded Costs (1)	(1.3)	—	—	—

(1) These amounts were reclassified to securitized regulatory assets in connection with the divestiture of PSNH's generation business. For further information see Note 2, "Regulatory Accounting" to the financial statements.

The following is a summary of the remaining Regulatory Assets and Accumulated Other Comprehensive Income amounts that have not been recognized as components of net periodic benefit expense as of December 31, 2018 and 2017, as well as the amounts that are expected to be recognized as components in 2019:

	Regulatory Assets as of December 31,		Expected 2019 Expense	AOCI as of December 31,		Expected 2019 Expense
(Millions of Dollars)	2018	2017		2018	2017	
Actuarial Loss	$ 207.3	$ 211.6	$ 9.9	$ 5.0	$ 6.6	$ 0.3
Prior Service (Credit)/Cost	(197.6)	(221.2)	(23.6)	2.6	2.6	0.2

Estimated Future Benefit Payments: The following benefit payments, which reflect expected future service, are expected to be paid by the Pension, SERP and PBOP Plans:

(Millions of Dollars)	2019	2020	2021	2022	2023	2024 - 2028
Pension and SERP	$ 308.5	$ 310.4	$ 318.8	$ 326.6	$ 335.6	$ 1,764.1
PBOP	58.4	58.5	58.6	58.3	57.8	277.4

Eversource Contributions: Based on the current status of the Pension Plans and federal pension funding requirements, Eversource currently expects to make contributions of approximately $112 million in 2019, of which approximately $44 million and $10 million will be contributed by CL&P and PSNH, respectively. The remaining $46 million is expected to be contributed by other Eversource subsidiaries, primarily Eversource Service. Eversource expects to make approximately $11 million in contributions to the PBOP Plan in 2019, of which approximately $6 million will be contributed by NSTAR Electric.

Fair Value of Pension and PBOP Plan Assets: Pension and PBOP funds are held in external trusts. Trust assets, including accumulated earnings, must be used exclusively for Pension and PBOP payments. Eversource's investment strategy for its Pension and PBOP Plans is to maximize the long-term rates of return on these plans' assets within an acceptable level of risk. The investment strategy for each asset category includes a diversification of asset types, fund strategies and fund managers and it establishes target asset allocations that are routinely reviewed and periodically rebalanced. PBOP assets are comprised of assets held in the PBOP Plan trust, as well as specific assets within the Pension Plan trust (401(h) assets). The investment policy and strategy of the 401(h) assets is consistent with that of the defined benefit pension plan. Eversource's expected long-term rates of return on Pension and PBOP Plan assets are based on target asset allocation assumptions and related expected long-term rates of return. In developing its expected long-term rate of return assumptions for the Pension and PBOP Plans, Eversource evaluated input from consultants, as well as long-term inflation assumptions and historical returns. For the year ended December 31, 2018, management has assumed long-term rates of return of 8.25 percent for the Eversource Service Pension and PBOP Plan assets. Management has assumed a 7 percent long-term rate of return for the Aquarion Plans.

These long-term rates of return are based on the assumed rates of return for the target asset allocations as follows:

	As of December 31,			
	2018		2017	
	Eversource Pension Plan and Tax-Exempt Assets Within PBOP Plan		Eversource Pension Plan and Tax-Exempt Assets Within PBOP Plan	
	Target Asset Allocation	Assumed Rate of Return	Target Asset Allocation	Assumed Rate of Return
Equity Securities:				
United States	15.0%	8.5%	21.5%	8.5%
Global	10.0%	8.75%	—%	—%
Non-United States	8.0%	8.5%	11.0%	8.5%
Emerging Markets	4.0%	10.0%	4.5%	10.0%
Debt Securities:				
Fixed Income	13.0%	4.0%	11.0%	4.0%
Public High Yield Fixed Income	4.0%	6.5%	4.0%	6.5%
Private Debt	15.0%	9.0%	15.0%	9.0%
Emerging Markets Debt	—%	—%	2.0%	6.5%
Private Equity	15.0%	12.0%	15.0%	12.0%
Real Assets	16.0%	7.5%	12.0%	7.5%
Hedge Funds	—%	—%	4.0%	6.0%

The taxable assets within the Eversource PBOP Plan have a target asset allocation of 70 percent equity securities and 30 percent fixed income securities. The target asset allocation for the Aquarion Pension Plans is 59 percent equity, 36 percent debt and 5 percent other. The target asset allocation for the Aquarion PBOP Plan is 59 percent equity and 41 percent debt.

The following table presents, by asset category, the Pension and PBOP Plan assets recorded at fair value on a recurring basis by the level in which they are classified within the fair value hierarchy:

	Pension Plan							
	Fair Value Measurements as of December 31,							
(Millions of Dollars)	2018				2017			
Asset Category:	Level 1	Level 2	Uncategorized	Total	Level 1	Level 2	Uncategorized	Total
Equity Securities (1)	$ 443.4	$ —	$ 1,377.8	$ 1,821.2	$ 535.4	$ —	$ 1,653.3	$ 2,188.7
Fixed Income (2)	85.5	160.8	1,265.5	1,511.8	56.6	215.9	1,218.3	1,490.8
Private Equity	6.1	—	834.0	840.1	11.2	—	641.8	653.0
Real Assets (3)	62.9	—	569.1	632.0	101.6	—	539.9	641.5
Total	$ 597.9	$ 160.8	$ 4,046.4	$ 4,805.1	$ 704.8	$ 215.9	$ 4,053.3	$ 4,974.0
Less: 401(h) PBOP Assets (4)				(231.2)				(234.5)
Total Pension Assets				$ 4,573.9				$ 4,739.5

	PBOP Plan							
	Fair Value Measurements as of December 31,							
(Millions of Dollars)	2018				2017			
Asset Category:	**Level 1**	**Level 2**	**Uncategorized**	**Total**	**Level 1**	**Level 2**	**Uncategorized**	**Total**
Equity Securities (1)	$ 91.9	$ —	$ 210.5	$ 302.4	$ 115.3	$ —	$ 241.9	$ 357.2
Fixed Income (2)	22.0	40.3	123.0	185.3	23.4	44.0	133.9	201.3
Private Equity	—	—	32.7	32.7	—	—	31.3	31.3
Real Assets (3)	27.5	—	70.5	98.0	22.4	—	75.5	97.9
Total	$ 141.4	$ 40.3	$ 436.7	$ 618.4	$ 161.1	$ 44.0	$ 482.6	$ 687.7
Add: 401(h) PBOP Assets (4)				231.2				234.5
Total PBOP Assets				$ 849.6				$ 922.2

(1) United States, Global, Non-United States and Emerging Markets equity securities that are uncategorized include investments in commingled funds and hedge funds that are overlayed with equity index swaps and futures contracts.

(2) Fixed Income investments that are uncategorized include investments in commingled funds, fixed income funds that invest in a variety of opportunistic and fixed income strategies, and hedge funds that are overlayed with fixed income futures.

(3) Real assets include real estate funds and hedge funds.

(4) The assets of the Pension Plan include a 401(h) account that has been allocated to provide health and welfare postretirement benefits under the PBOP Plan.

The Company values assets based on observable inputs when available. Equity securities, exchange traded funds and futures contracts classified as Level 1 in the fair value hierarchy are priced based on the closing price on the primary exchange as of the balance sheet date.

Fixed income securities, such as government issued securities, corporate bonds and high yield bond funds, are included in Level 2 and are valued using pricing models, quoted prices of securities with similar characteristics or discounted cash flows. The pricing models utilize observable inputs such as recent trades for the same or similar instruments, yield curves, discount margins and bond structures. Swaps are valued using pricing models that incorporate interest rates and equity and fixed income index closing prices to determine a net present value of the cash flows.

Certain investments, such as commingled funds, private equity investments, real estate funds and hedge funds are valued using the NAV as a practical expedient. These investments are structured as investment companies offering shares or units to multiple investors for the purpose of providing a return. Commingled funds are recorded at NAV provided by the asset manager, which is based on the market prices of the underlying equity securities. Private Equity investments, Fixed Income partnership funds and Real Assets are valued using the NAV provided by the partnerships, which are based on discounted cash flows of the underlying investments, real estate appraisals or public market comparables of the underlying investments, or the NAV of underlying assets held in hedge funds. Assets valued at NAV are uncategorized in the fair value hierarchy.

B. Defined Contribution Plans

Eversource maintains defined contribution plans on behalf of eligible participants. The Eversource 401k Plan provides for employee and employer contributions up to statutory limits. For eligible employees, the Eversource 401k Plan provides employer matching contributions of either 100 percent up to a maximum of three percent of eligible compensation or 50 percent up to a maximum of eight percent of eligible compensation. The Eversource 401k Plan also contains a K-Vantage feature for the benefit of eligible participants, which provides an additional annual employer contribution based on age and years of service. K-Vantage participants are not eligible to actively participate in the Eversource Pension Plan.

The total Eversource 401k Plan employer matching contributions, including the K-Vantage contributions, were as follows:

(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
2018	$ 38.4	$ 5.0	$ 9.7	$ 3.3
2017	34.5	4.6	8.5	3.7
2016	31.8	4.5	8.1	3.4

C. Share-Based Payments

Share-based compensation awards are recorded using a fair-value based method at the date of grant. Eversource, CL&P, NSTAR Electric and PSNH record compensation expense related to these awards, as applicable, for shares issued or sold to their respective employees and officers, as well as for the allocation of costs associated with shares issued or sold to Eversource's service company employees and officers that support CL&P, NSTAR Electric and PSNH.

Eversource Incentive Plans: Eversource maintains long-term equity-based incentive plans in which Eversource, CL&P, NSTAR Electric and PSNH employees, officers and board members are eligible to participate. The incentive plans authorize Eversource to grant up to 6,700,000 new shares for various types of awards, including RSUs and performance shares, to eligible employees, officers, and board members. As of December 31, 2018 and 2017, Eversource had 3,720,650 and 2,445,110 common shares, respectively, available for issuance under these plans.

Eversource accounts for its various share-based plans as follows:

- RSUs - Eversource records compensation expense, net of estimated forfeitures, on a straight-line basis over the requisite service period based upon the fair value of Eversource's common shares at the date of grant. The par value of RSUs is reclassified to Common Stock from APIC as RSUs become issued as common shares.

- Performance Shares - Eversource records compensation expense, net of estimated forfeitures, on a straight-line basis over the requisite service period. Performance shares vest based upon the extent to which Company goals are achieved. Vesting of outstanding performance shares is based upon both the Company's EPS growth over the requisite service period and the total shareholder return as compared to the Edison Electric Institute ("EEI") Index during the requisite service period. The fair value of performance shares is determined at the date of grant using a lattice model.

RSUs: Eversource granted RSUs under the annual long-term incentive programs that are subject to three-year graded vesting schedules for employees, and one-year graded vesting schedules, or immediate vesting, for board members. RSUs are paid in shares, reduced by amounts sufficient to satisfy withholdings for income taxes, subsequent to vesting. A summary of RSU transactions is as follows:

	RSUs (Units)	Weighted Average Grant-Date Fair Value
Outstanding as of December 31, 2017	717,039	$ 49.29
Granted	286,315	$ 56.69
Shares Issued	(201,386)	$ 55.35
Forfeited	(19,603)	$ 56.78
Outstanding as of December 31, 2018	782,365	$ 50.25

The weighted average grant-date fair value of RSUs granted for the years ended December 31, 2018, 2017 and 2016 was $56.69, $55.97 and $54.67, respectively. As of December 31, 2018 and 2017, the number and weighted average grant-date fair value of unvested RSUs was 424,119 and $56.57 per share, and 388,269 and $56.15 per share, respectively. During 2018, there were 216,572 RSUs at a weighted average grant-date fair value of $56.72 per share that vested during the year and were either paid or deferred. As of December 31, 2018, 358,246 RSUs were fully vested and deferred and an additional 402,913 are expected to vest.

Performance Shares: Eversource granted performance shares under the annual long-term incentive programs that vest based upon the extent to which Company goals are achieved at the end of three-year performance measurement periods. Performance shares are paid in shares, after the performance measurement period. A summary of performance share transactions is as follows:

	Performance Shares (Units)	Weighted Average Grant-Date Fair Value
Outstanding as of December 31, 2017	510,565	$ 55.45
Granted	184,355	$ 56.77
Shares Issued	(178,258)	$ 54.98
Forfeited	(17,098)	$ 56.18
Outstanding as of December 31, 2018	499,564	$ 56.08

The weighted average grant-date fair value of performance shares granted for the years ended December 31, 2018, 2017 and 2016 was $56.77, $55.70 and $53.64, respectively. As of December 31, 2018 and 2017, the number and weighted average grant-date fair value of unvested performance shares was 366,995 and $56.17 per share, and 331,207 and $55.79 per share, respectively. During 2018, there were 131,349 performance shares at a weighted average grant-date fair value of $56.08 per share that vested during the year and were either paid or deferred. As of December 31, 2018, 132,569 performance shares were fully vested and deferred.

Compensation Expense: The total compensation expense and associated future income tax benefits recognized by Eversource, CL&P, NSTAR Electric and PSNH for share-based compensation awards were as follows:

Eversource	For the Years Ended December 31,		
(Millions of Dollars)	2018	2017	2016
Compensation Expense	$ 21.4	$ 19.7	$ 23.6
Future Income Tax Benefit	5.4	8.0	9.6

	For the Years Ended December 31,								
	2018			2017			2016		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Compensation Expense	$ 7.8	$ 7.7	$ 2.9	$ 7.0	$ 7.0	$ 3.2	$ 9.1	$ 8.2	$ 3.5
Future Income Tax Benefit	2.0	1.9	0.7	2.9	2.8	1.3	3.7	3.3	1.4

As of December 31, 2018, there was $22.3 million of total unrecognized compensation expense related to nonvested share-based awards for Eversource, including $8.1 million for CL&P, $8.0 million for NSTAR Electric and $2.8 million for PSNH. This cost is expected to be recognized ratably over a weighted-average period of 1.73 years for Eversource and CL&P, and 1.72 years for NSTAR Electric and PSNH.

An income tax rate of 25 percent was used to estimate the tax effect on total share-based payments determined under the fair-value based method for all awards. During both 2018 and 2017, the Company generally settled fully vested RSUs and performance shares with the issuance of common shares purchased in the open market.

For the years ended December 31, 2018, 2017 and 2016, excess tax benefits associated with the distribution of stock compensation awards reduced income tax expense by $1.5 million, $2.9 million, and $19.1 million, respectively, which increased cash flows from operating activities on the statements of cash flows.

D. Other Retirement Benefits

Eversource provides retirement and other benefits for certain current and past company officers. These benefits are accounted for on an accrual basis and expensed over a period equal to the service lives of the employees. The actuarially-determined liability for these benefits, which is included in Other Long-Term Liabilities on the balance sheets, as well as the related expense included in Operations and Maintenance Expense on the income statements, are as follows:

Eversource *(Millions of Dollars)*	**As of and For the Years Ended December 31,**		
	2018	**2017**	**2016**
Actuarially-Determined Liability	$ 49.1	$ 53.4	$ 54.2
Other Retirement Benefits Expense	2.7	2.8	2.9

	As of and For the Years Ended December 31,								
	2018			**2017**			**2016**		
(Millions of Dollars)	**CL&P**	**NSTAR Electric**	**PSNH**	**CL&P**	**NSTAR Electric**	**PSNH**	**CL&P**	**NSTAR Electric**	**PSNH**
Actuarially-Determined Liability	$ 0.3	$ 0.1	$ 1.7	$ 0.3	$ 0.1	$ 1.9	$ 0.3	$ 0.1	$ 2.0
Other Retirement Benefits Expense	1.1	1.1	0.4	1.0	1.0	0.5	1.1	0.9	0.6

11. INCOME TAXES

The components of income tax expense are as follows:

Eversource *(Millions of Dollars)*	**For the Years Ended December 31,**		
	2018	**2017**	**2016**
Current Income Taxes:			
Federal	$ 106.5	$ 58.9	$ 38.9
State	10.6	31.6	53.0
Total Current	117.1	90.5	91.9
Deferred Income Taxes, Net:			
Federal	122.6	433.0	427.9
State	52.2	58.6	38.6
Total Deferred	174.8	491.6	466.5
Investment Tax Credits, Net	(2.9)	(3.2)	(3.4)
Income Tax Expense	$ 289.0	$ 578.9	$ 555.0

	For the Years Ended December 31,								
	2018			2017			2016		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Current Income Taxes:									
Federal	$ 54.2	$ 79.3	$ 12.2	$ 50.9	$ 107.8	$ 18.6	$ 27.3	$ 86.4	$ (13.7)
State	20.9	30.0	(0.5)	17.4	25.6	6.2	13.3	39.5	8.8
Total Current	75.1	109.3	11.7	68.3	133.4	24.8	40.6	125.9	(4.9)
Deferred Income Taxes, Net:									
Federal	48.5	27.9	15.4	123.9	88.1	52.7	157.6	96.6	79.5
State	6.4	13.5	20.5	(4.6)	22.4	11.2	11.3	5.1	7.8
Total Deferred	54.9	41.4	35.9	119.3	110.5	63.9	168.9	101.7	87.3
Investment Tax Credits, Net	(0.9)	(1.8)	—	(1.0)	(1.8)	—	(1.2)	(1.8)	—
Income Tax Expense	$ 129.1	$ 148.9	$ 47.6	$ 186.6	$ 242.1	$ 88.7	$ 208.3	$ 225.8	$ 82.4

A reconciliation between income tax expense and the expected tax expense at the statutory rate is as follows:

Eversource *(Millions of Dollars, except percentages)*	For the Years Ended December 31,		
	2018	2017	2016
Income Before Income Tax Expense	$ 1,329.5	$ 1,574.4	$ 1,504.8
Statutory Federal Income Tax Expense at 21% in 2018 and 35% in 2017 and 2016	279.2	551.0	526.7
Tax Effect of Differences:			
Depreciation	(30.8)	(10.8)	(3.4)
Investment Tax Credit Amortization	(2.9)	(3.2)	(3.4)
Other Federal Tax Credits	—	—	(3.5)
State Income Taxes, Net of Federal Impact	44.4	47.7	56.2
Dividends on ESOP	(5.1)	(8.4)	(8.4)
Tax Asset Valuation Allowance/Reserve Adjustments	5.2	7.0	3.3
Excess Stock Benefit	(1.5)	(2.9)	(19.1)
Other, Net	0.5	(1.5)	6.6
Income Tax Expense	$ 289.0	$ 578.9	$ 555.0
Effective Tax Rate	21.7%	36.8%	36.9%

	For the Years Ended December 31,								
	2018			2017			2016		
(Millions of Dollars,except percentages)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Income Before Income Tax Expense	$ 506.8	$ 532.0	$ 163.5	$ 563.4	$ 616.8	$ 224.7	$ 542.6	$ 576.6	$ 214.3
Statutory Federal Income Tax Expense at 21% in 2018 and 35% in 2017 and 2016	106.4	111.7	34.3	197.2	215.9	78.6	189.9	201.8	75.0
Tax Effect of Differences:									
Depreciation	(1.2)	(2.8)	0.1	(5.2)	(3.0)	1.1	1.6	(3.1)	1.0
Investment Tax Credit Amortization	(0.9)	(1.8)	—	(1.0)	(1.8)	—	(1.2)	(1.8)	—
Other Federal Tax Credits	—	—	—	—	—	—	—	—	(3.5)
State Income Taxes, Net of Federal Impact	14.5	33.2	15.8	4.5	31.2	11.3	14.5	29.0	10.8
Tax Asset Valuation Allowance/Reserve Adjustments	7.1	1.2	—	(9.5)	—	—	1.5	—	—
Excess Stock Benefit	(0.1)	(0.1)	(0.1)	(0.7)	(0.7)	(0.3)	(0.9)	(1.2)	(0.4)
Other, Net	3.3	7.5	(2.5)	1.3	0.5	(2.0)	2.9	1.1	(0.5)
Income Tax Expense	$ 129.1	$ 148.9	$ 47.6	$ 186.6	$ 242.1	$ 88.7	$ 208.3	$ 225.8	$ 82.4
Effective Tax Rate	25.5%	28.0%	29.1%	33.1%	39.2%	39.5%	38.4%	39.2%	38.4%

Eversource, CL&P, NSTAR Electric and PSNH file a consolidated federal income tax return and unitary, combined and separate state income tax returns. These entities are also parties to a tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized.

Deferred tax assets and liabilities are recognized for the future tax effects of temporary differences between the carrying amounts and the tax basis of assets and liabilities. The tax effect of temporary differences is accounted for in accordance with the rate-making treatment of the applicable regulatory commissions and relevant accounting authoritative literature. The tax effects of temporary differences that give rise to the net accumulated deferred income tax obligations are as follows:

	As of December 31,							
	2018				2017			
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Eversource	CL&P	NSTAR Electric	PSNH
Deferred Tax Assets:								
Employee Benefits	$ 388.2	$ 94.5	$ 35.0	$ 31.1	$ 442.1	$ 112.3	$ 34.0	$ 38.0
Derivative Liabilities	111.4	111.4	—	—	111.8	110.5	0.3	—
Regulatory Deferrals - Liabilities	299.3	38.6	195.5	16.1	205.6	12.0	139.8	17.9
Allowance for Uncollectible Accounts	54.0	23.1	17.8	3.0	50.1	20.6	17.3	2.9
Tax Effect - Tax Regulatory Liabilities	830.3	336.8	288.9	111.7	832.6	337.2	281.2	116.8
Net Operating Loss Carryforwards	28.5	—	—	0.6	47.8	—	—	—
Purchase Accounting Adjustment	64.2	—	—	—	69.9	—	—	—
Other	166.2	81.1	15.6	33.4	149.5	70.7	4.9	49.6
Total Deferred Tax Assets	1,942.1	685.5	552.8	195.9	1,909.4	663.3	477.5	225.2
Less: Valuation Allowance	19.5	10.7	—	—	14.6	6.3	—	—
Net Deferred Tax Assets	$ 1,922.6	$ 674.8	$ 552.8	$ 195.9	$ 1,894.8	$ 657.0	$ 477.5	$ 225.2
Deferred Tax Liabilities:								
Accelerated Depreciation and Other Plant-Related Differences	$ 3,724.2	$ 1,293.3	$ 1,342.4	$ 410.6	$ 3,562.0	$ 1,224.9	$ 1,229.2	$ 502.5
Property Tax Accruals	73.2	35.4	26.3	5.2	56.7	20.7	24.2	5.5
Regulatory Amounts:								
Regulatory Deferrals - Assets	1,025.9	320.1	277.4	213.8	924.9	310.6	267.1	103.6
Tax Effect - Tax Regulatory Assets	238.9	167.0	9.7	8.1	243.1	173.1	9.8	11.4
Goodwill Regulatory Asset - 1999 Merger	95.2	—	81.7	—	99.8	—	85.7	—
Derivative Assets	20.1	19.9	—	—	17.4	17.4	—	—
Other	251.1	5.9	109.8	39.4	288.4	13.7	137.3	45.7
Total Deferred Tax Liabilities	$ 5,428.6	$ 1,841.6	$ 1,847.3	$ 677.1	$ 5,192.3	$ 1,760.4	$ 1,753.3	$ 668.7

2017 Federal Legislation: On December 22, 2017, the Tax Cuts and Jobs Act became law, which amended existing federal tax rules and included numerous provisions that impacted corporations. In particular, the act reduced the U.S. federal corporate income tax rate from 35 percent to 21 percent effective January 1, 2018. For our regulated companies, the most significant changes are (1) the benefit of incurring a lower federal income tax expense and (2) the reduction in ADIT liabilities (now excess ADIT or EDIT), which were estimated to be approximately $2.9 billion and included in regulatory liabilities as of December 31, 2018. In 2018, Eversource refunded $5.0 million ($4.4 million at PSNH and $0.6 million at Yankee Gas) to customers. See Note 2, "Regulatory Accounting," to the financial statements for further information.

The Company assessed the applicable provisions in the act and recorded the associated impacts as of December 31, 2017. The Company recorded the provisional income tax amounts as of December 31, 2017 in accordance with SEC Staff Accounting Bulletin No. 118 ("SAB 118") issued by the SEC in December 2017, for changes pursuant to the act because the impacts could not be finalized upon issuance of the financial statements, but for which reasonable estimates could be determined. The Company has completed its evaluation of the impacts of the act as of December 31, 2018. The

ultimate outcome was not materially different from the provisional estimates recorded as of December 31, 2017. While the Company has recorded the impacts of the act based on interpretation of the provisions as enacted, it is expected the U.S. Department of Treasury and the IRS will issue additional interpretative guidance in the future that could result in changes to previously finalized provisions. At this time, some of the states in which the Company does business have issued guidance regarding the act and the impact was not material.

Carryforwards: The following tables provide the amounts and expiration dates of state tax credit and loss carryforwards and federal tax credit and net operating loss carryforwards:

	As of December 31,									
	2018					2017				
(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH	Expiration Range	Eversource	CL&P	NSTAR Electric	PSNH	Expiration Range
Federal Net Operating Loss	$ 103.6	$ —	$ —	$ —	2033 - 2037	$ 197.3	$ —	$ —	$ —	2027 - 2037
Federal Charitable Contribution	2.2	—	—	—	2020 - 2022	18.7	—	—	—	2017 - 2022
State Net Operating Loss	80.7	—	—	—	2019 - 2038	82.8	—	—	—	2028 - 2037
State Tax Credit	148.9	107.0	—	—	2018 - 2023	139.0	94.5	—	—	2017 - 2022
State Charitable Contribution	9.6	—	—	—	2019 - 2023	31.4	—	—	—	2017 - 2022

In 2018, the company increased its valuation allowance reserve for state credits by $5.2 million ($4.4 million for CL&P), net of tax, to reflect an update for expired tax credits. In 2017, the Company increased its valuation allowance reserve for state credits by $9.9 million ($1.8 million for CL&P), net of tax, to reflect an update for expired tax credits.

For 2018 and 2017, state credit and state loss carryforwards have been partially reserved by a valuation allowance of $19.5 million and $14.4 million (net of tax), respectively.

Unrecognized Tax Benefits: A reconciliation of the activity in unrecognized tax benefits, all of which would impact the effective tax rate if recognized, is as follows:

(Millions of Dollars)	Eversource	CL&P
Balance as of January 1, 2016	$ 48.0	$ 13.5
Gross Increases - Current Year	9.9	3.9
Gross Increases - Prior Year	0.2	0.2
Lapse of Statute of Limitations	(9.7)	(2.3)
Balance as of December 31, 2016	48.4	15.3
Gross Increases - Current Year	11.4	4.7
Gross Decreases - Prior Year	(0.9)	(0.5)
Lapse of Statute of Limitations	(7.2)	(1.4)
Balance as of December 31, 2017	51.7	18.1
Gross Increases - Current Year	9.2	3.2
Gross Decreases - Prior Year	(6.5)	(0.9)
Lapse of Statute of Limitations	(8.5)	(2.2)
Balance as of December 31, 2018	$ 45.9	$ 18.2

Interest and Penalties: Interest on uncertain tax positions is recorded and generally classified as a component of Other Interest Expense on the statements of income. However, when resolution of uncertainties results in the Company receiving interest income, any related interest benefit is recorded in Other Income, Net on the statements of income. No penalties have been recorded. The amount of interest expense/(income) on uncertain tax positions recognized and the related accrued interest payable/(receivable) are as follows:

	Other Interest Expense/(Income)			Accrued Interest Expense	
	For the Years Ended December 31,			As of December 31,	
(Millions of Dollars)	2018	2017	2016	2018	2017
Eversource	$ (1.7)	$ —	$ (0.2)	$ 0.1	$ 1.8

Tax Positions: During 2018 and 2017, Eversource did not resolve any of its uncertain tax positions.

Open Tax Years: The following table summarizes Eversource, CL&P, NSTAR Electric and PSNH's tax years that remain subject to examination by major tax jurisdictions as of December 31, 2018:

Description	Tax Years
Federal	2018
Connecticut	2015 - 2018
Massachusetts	2015 - 2018
New Hampshire	2016 - 2018

Eversource does not estimate to have an earnings impact related to unrecognized tax benefits during the next twelve months.

12. COMMITMENTS AND CONTINGENCIES

A. Environmental Matters

General: Eversource, CL&P, NSTAR Electric and PSNH are subject to environmental laws and regulations intended to mitigate or remove the effect of past operations and improve or maintain the quality of the environment. These laws and regulations require the removal or the remedy of the effect on the environment of the disposal or release of certain specified hazardous substances at current and former operating sites. Eversource, CL&P, NSTAR Electric and PSNH have an active environmental auditing and training program and each believes it is substantially in compliance with all enacted laws and regulations.

Environmental reserves are accrued when assessments indicate it is probable that a liability has been incurred and an amount can be reasonably estimated. The approach used estimates the liability based on the most likely action plan from a variety of available remediation options, including no action required or several different remedies ranging from establishing institutional controls to full site remediation and monitoring. These liabilities are estimated on an undiscounted basis and do not assume that the amounts are recoverable from insurance companies or other third parties. The environmental reserves include sites at different stages of discovery and remediation and do not include any unasserted claims.

These reserve estimates are subjective in nature as they take into consideration several different remediation options at each specific site. The reliability and precision of these estimates can be affected by several factors, including new information concerning either the level of contamination at the site, the extent of Eversource's, CL&P's, NSTAR Electric's and PSNH's responsibility for remediation or the extent of remediation required, recently enacted laws and regulations or changes in cost estimates due to certain economic factors. It is possible that new information or future developments could require a reassessment of the potential exposure to required environmental remediation. As this information becomes available, management will continue to assess the potential exposure and adjust the reserves accordingly.

The amounts recorded as environmental reserves are included in Other Current Liabilities and Other Long-Term Liabilities on the balance sheets and represent management's best estimate of the liability for environmental costs, and take into consideration site assessment, remediation and long-term monitoring costs. The environmental reserves also take into account recurring costs of managing hazardous substances and pollutants, mandated expenditures to remediate contaminated sites and any other infrequent and non-recurring clean-up costs. A reconciliation of the activity in the environmental reserves is as follows:

(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
Balance as of January 1, 2017	$ 65.8	$ 4.9	$ 3.8	$ 5.3
Additions	6.2	0.5	1.8	1.0
Payments/Reductions	(17.1)	(0.7)	(2.9)	(0.6)
Balance as of December 31, 2017	54.9	4.7	2.7	5.7
Additions	23.5	1.9	9.7	—
Payments/Reductions	(13.7)	(1.2)	(1.5)	(0.3)
Balance as of December 31, 2018	$ 64.7	$ 5.4	$ 10.9	$ 5.4

The number of environmental sites for which remediation or long-term monitoring, preliminary site work or site assessment is being performed are as follows:

	Eversource	CL&P	NSTAR Electric	PSNH
2018	60	15	16	9
2017	59	14	15	10

The increase in the reserve balance was due primarily to the addition of environmental sites at NSTAR Electric and changes in cost estimates at certain MGP sites at our natural gas companies under investigation for which additional remediation will be required.

Included in the Eversource number of sites and reserve amounts above are former MGP sites that were operated several decades ago and manufactured gas from coal and other processes, which resulted in certain by-products remaining in the environment that may pose a potential risk to human health and the environment, for which Eversource may have potential liability. The reserve balances related to these former MGP sites were $50.1 million and $49.0 million as of December 31, 2018 and 2017, respectively, and related primarily to the natural gas business segment.

As of December 31, 2018, for 7 environmental sites (2 for CL&P) that are included in the Company's reserve for environmental costs, the information known and the nature of the remediation options allow for the Company to estimate the range of losses for environmental costs. As of December 31, 2018, $23.8 million (including $0.7 million for CL&P) had been accrued as a liability for these sites, which represents the low end of the range of the liabilities for environmental costs. Management believes that additional losses of up to approximately $20 million ($1 million at CL&P) may be incurred in executing current remediation plans for these sites.

As of December 31, 2018, for 12 environmental sites (4 for CL&P and 3 for NSTAR Electric) that are included in the Company's reserve for environmental costs, management cannot reasonably estimate the exposure to loss in excess of the reserve, or range of loss, as these sites are under investigation and/or there is significant uncertainty as to what remedial actions, if any, the Company may be required to undertake. As of December 31, 2018, $11.1 million (including $1.9 million for CL&P and $1.9 million for NSTAR Electric) had been accrued as a liability for these sites. As of December 31, 2018, for the remaining 41 environmental sites (including 9 for CL&P, 13 for NSTAR Electric and 9 for PSNH) that are included in the Company's reserve for environmental costs, the $29.8 million accrual (including $2.8 million for CL&P, $9.0 million for NSTAR Electric and $5.4 million for PSNH) represents management's best estimate of the probable liability and no additional loss is anticipated at this time.

Environmental Rate Recovery: PSNH, NSTAR Gas and Yankee Gas have rate recovery mechanisms for MGP related environmental costs, therefore, changes in their respective environmental reserves do not impact Net Income. Effective with the May 2018 distribution rate case settlement, CL&P is allowed to defer certain environmental costs for future recovery. NSTAR Electric does not have a separate environmental cost recovery regulatory

mechanism.

B. Long-Term Contractual Arrangements

Estimated Future Annual Costs: The estimated future annual costs of significant executed, non-cancelable, long-term contractual arrangements in effect as of December 31, 2018 are as follows:

Eversource

(Millions of Dollars)	2019	2020	2021	2022	2023	Thereafter	Total
Purchased Power and Capacity	$ 68.3	$ 73.5	$ 69.1	$ 72.9	$ 74.1	$ 142.9	$ 500.8
Renewable Energy	262.4	261.0	238.9	240.5	217.2	1,662.0	2,882.0
Peaker CfDs	11.9	22.6	21.9	15.3	17.5	43.5	132.7
Natural Gas Procurement	243.8	227.7	183.6	149.2	135.1	1,039.7	1,979.1
Transmission Support Commitments	22.8	23.1	15.2	16.2	17.8	17.8	112.9
Total	$ 609.2	$ 607.9	$ 528.7	$ 494.1	$ 461.7	$ 2,905.9	$ 5,607.5

CL&P

(Millions of Dollars)	2019	2020	2021	2022	2023	Thereafter	Total
Purchased Power and Capacity	$ 57.0	$ 69.7	$ 65.3	$ 69.1	$ 70.4	$ 123.9	$ 455.4
Renewable Energy	102.0	103.8	104.0	104.9	105.5	785.3	1,305.5
Peaker CfDs	11.9	22.6	21.9	15.3	17.5	43.5	132.7
Transmission Support Commitments	9.0	9.1	6.0	6.4	7.0	7.0	44.5
Total	$ 179.9	$ 205.2	$ 197.2	$ 195.7	$ 200.4	$ 959.7	$ 1,938.1

NSTAR Electric

(Millions of Dollars)	2019	2020	2021	2022	2023	Thereafter	Total
Purchased Power and Capacity	$ 5.5	$ 3.1	$ 3.1	$ 3.1	$ 3.0	$ 19.0	$ 36.8
Renewable Energy	94.7	93.1	88.6	88.8	63.9	435.1	864.2
Transmission Support Commitments	9.0	9.1	6.0	6.3	7.0	7.0	44.4
Total	$ 109.2	$ 105.3	$ 97.7	$ 98.2	$ 73.9	$ 461.1	$ 945.4

PSNH

(Millions of Dollars)	2019	2020	2021	2022	2023	Thereafter	Total
Purchased Power and Capacity	$ 5.8	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ —	$ 8.6
Renewable Energy	65.7	64.1	46.3	46.8	47.8	441.6	712.3
Transmission Support Commitments	4.8	4.9	3.2	3.5	3.8	3.8	24.0
Total	$ 76.3	$ 69.7	$ 50.2	$ 51.0	$ 52.3	$ 445.4	$ 744.9

Purchased Power and Capacity: CL&P, NSTAR Electric and PSNH have various IPP contracts or purchase obligations for electricity. Such contracts extend through 2024 for CL&P, 2031 for NSTAR Electric and 2023 for PSNH.

In addition, CL&P, along with UI, has four capacity CfDs for a total of approximately 787 MW of capacity consisting of three generation units and one demand response project. The capacity CfDs extend through 2026 and obligate both CL&P and UI to make or receive payments on a monthly basis to or from the generation facilities based on the difference between a set contractual capacity price and the capacity market prices received by the generation facilities in the ISO-NE capacity markets. CL&P has a sharing agreement with UI, whereby UI shares 20 percent of the costs and

benefits of these contracts. CL&P's portion of the costs and benefits of these contracts will be paid by, or refunded to, CL&P's customers.

The contractual obligations table above does not include CL&P's, NSTAR Electric's or PSNH's standard/basic service contracts, the amounts of which vary with customers' energy needs.

Renewable Energy: Renewable energy contracts include non-cancellable commitments under contracts of CL&P, NSTAR Electric and PSNH for the purchase of energy and capacity from renewable energy facilities. Such contracts extend through 2039 for CL&P, 2038 for NSTAR Electric and 2033 for PSNH.

The contractual obligations table above does not include long-term commitments signed by CL&P and NSTAR Electric, as required by the PURA and DPU, respectively, for the purchase of renewable energy and related products that are contingent on the future construction of energy facilities. The table also excludes certain CL&P long-term commitments required by regulation that have not yet been executed such as the selection of certain nuclear power-generating facilities awarded under the Act Concerning Zero Carbon Solicitation and Procurement.

Peaker CfDs: In 2008, CL&P entered into three CfDs with developers of peaking generation units approved by PURA (Peaker CfDs). These units have a total of approximately 500 MW of peaking capacity. As directed by PURA, CL&P and UI have entered into a sharing agreement, whereby CL&P is responsible for 80 percent and UI for 20 percent of the net costs or benefits of these CfDs. The Peaker CfDs pay the generation facility owner the difference between capacity, forward reserve and energy market revenues and a cost-of-service payment stream for 30 years. The ultimate cost or benefit to CL&P under these contracts will depend on the costs of plant operation and the prices that the projects receive for capacity and other products in the ISO-NE markets. CL&P's portion of the amounts paid or received under the Peaker CfDs will be recoverable from, or refunded to, CL&P's customers.

Natural Gas Procurement: In the normal course of business, Eversource's natural gas distribution businesses have long-term contracts for the purchase, transportation and storage of natural gas as part of its portfolio of supplies. These contracts extend through 2034.

Transmission Support Commitments: Along with other New England utilities, CL&P, NSTAR Electric and PSNH entered into agreements in 1985 to support transmission and terminal facilities that were built to import electricity from the Hydro-Québec system in Canada. CL&P, NSTAR Electric and PSNH are obligated to pay, over a 30-year period ending in 2020, their proportionate shares of the annual operation and maintenance expenses and capital costs of those facilities.

The total costs incurred under these agreements were as follows:

Eversource	**For the Years Ended December 31,**		
(Millions of Dollars)	**2018**	**2017**	**2016**
Purchased Power and Capacity	$ 72.0	$ 103.9	$ 152.5
Renewable Energy	218.5	235.5	210.9
Peaker CfDs	20.9	38.7	47.7
Natural Gas Procurement	432.4	377.0	323.9
Transmission Support Commitments	23.4	19.8	15.9
Coal, Wood and Other (1)	—	47.7	55.7

	For the Years Ended December 31,								
	2018			2017			2016		
(Millions of Dollars)	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH	CL&P	NSTAR Electric	PSNH
Purchased Power and Capacity	$ 49.4	$ 4.4	$ 18.2	$ 81.0	$ 4.0	$ 18.9	$ 132.7	$ 0.7	$ 19.1
Renewable Energy	63.2	89.8	65.5	51.0	123.7	60.8	42.1	101.1	67.7
Peaker CfDs	20.9	—	—	38.7	—	—	47.7	—	—
Transmission Support Commitments	9.2	9.2	5.0	7.8	7.8	4.2	6.3	6.2	3.4
Coal, Wood and Other (1)	—	—	—	—	—	47.7	—	—	55.7

(1) PSNH previously entered into various arrangements for the purchase of coal, wood and the transportation services for fuel supply for its electric generating assets. On January 10, 2018, Eversource and PSNH completed the sale of PSNH's thermal generation assets. On August 26, 2018, Eversource and PSNH completed the sale of PSNH's hydroelectric generation assets. Upon sale, the remaining future contractual obligations were transferred to the respective buyers. See Note 13, "Generation Asset Sale," for further information.

C. Spent Nuclear Fuel Obligations - Yankee Companies

CL&P, NSTAR Electric and PSNH have plant closure and fuel storage cost obligations to the Yankee Companies, which have each completed the physical decommissioning of their respective nuclear facilities and are now engaged in the long-term storage of their spent fuel. The Yankee Companies have collected these costs through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including CL&P, NSTAR Electric and PSNH. These companies in turn recover these costs from their customers through state regulatory commission-approved retail rates. The Yankee Companies have collected amounts that management believes are adequate to recover the remaining plant closure and fuel storage cost estimates for the respective plants. Management believes CL&P and NSTAR Electric will recover their shares of these obligations from their customers. PSNH has recovered its total share of these costs from its customers.

Spent Nuclear Fuel Litigation:

The Yankee Companies have filed complaints against the DOE in the Court of Federal Claims seeking monetary damages resulting from the DOE's failure to provide for a permanent facility to store spent nuclear fuel pursuant to the terms of the 1983 spent fuel and high level waste disposal contracts between the Yankee Companies and the DOE. The court had previously awarded the Yankee Companies damages for Phase I, II and III of litigation resulting from the DOE's failure to meet its contractual obligations. These Phases covered damages incurred in the years 1998 through 2012, and the awarded damages have been received by the Yankee Companies with certain amounts of the damages refunded to their customers.

DOE Phase III Damages - In August 2013, the Yankee Companies each filed subsequent lawsuits against the DOE seeking recovery of actual damages incurred in the years 2009 through 2012 ("DOE Phase III"). On March 25, 2016, the court issued its decision and awarded CYAPC, YAEC and MYAPC damages of $32.6 million, $19.6 million and $24.6 million, respectively. The decision became final on July 18, 2016, and the Yankee Companies received the awards from the DOE on October 14, 2016. The Yankee Companies received FERC approval of their proposed distribution of certain amounts of the awarded damages proceeds to member companies, including CL&P, NSTAR Electric and PSNH, which CYAPC and MYAPC made in December 2016. MYAPC also refunded $56.5 million from its spent nuclear fuel trust, a portion of which was also refunded to the Eversource utility subsidiaries. In total, Eversource received $26.1 million, of which CL&P, NSTAR Electric and PSNH received $13.6 million, $8.6 million and $3.9 million, respectively. These amounts have been refunded to the customers of the respective Eversource utility subsidiaries.

DOE Phase IV Damages - On May 22, 2017, each of the Yankee Companies filed subsequent lawsuits against the DOE in the Court of Federal Claims seeking monetary damages totaling approximately $100 million for CYAPC, YAEC and MYAPC, resulting from the DOE's failure to begin accepting spent nuclear fuel for disposal covering the years from 2013 to 2016 (“DOE Phase IV”). On February 21, 2019, the Yankee Companies received a partial summary judgment and partial final judgment in their favor for the undisputed amount of monetary damages, which is the vast majority of the damages being sought. The DOE Phase IV trial for the remaining amount of damages is expected to begin in 2019.

D. Guarantees and Indemnifications

In the normal course of business, Eversource parent provides credit assurances on behalf of its subsidiaries, including CL&P, NSTAR Electric and PSNH, in the form of guarantees.

Eversource parent issued a guaranty on behalf of its subsidiary, NPT, under which, beginning at the time the Northern Pass Transmission line goes into commercial operation, Eversource parent will guarantee the financial obligations of NPT under the TSA with HQ in an amount not to exceed $25 million. Eversource parent's obligations under the guaranty expire upon the full, final and indefeasible payment of the guaranteed obligations. Eversource parent has also entered into a guaranty on behalf of NPT under which Eversource parent will guarantee NPT's obligations under a facility with a financial institution pursuant to which NPT may request letters of credit in an aggregate amount of up to approximately $14 million.

Management does not anticipate a material impact to net income or cash flows as a result of these various guarantees and indemnifications. The following table summarizes Eversource parent's exposure to guarantees and indemnifications of its subsidiaries to external parties, as of December 31, 2018:

Company	Description	Maximum Exposure (in millions)	Expiration Dates
On behalf of subsidiaries:			
Eversource Gas Transmission LLC	Access Northeast Project Capital Contributions Guaranty (1)	$ 184.9	2021
Various	Surety Bonds (2)	41.9	2019 - 2021
Rocky River Realty Company and Eversource Service	Lease Payments for Real Estate	6.3	2019 - 2024
Bay State Wind LLC	Real Estate Purchase	2.5	2019

(1) Eversource parent issued a declining balance guaranty on behalf of its subsidiary, Eversource Gas Transmission LLC, to guarantee the payment of the subsidiary's authorized capital contributions for its investment in the Access Northeast project. The guaranty decreases as authorized capital contributions are made. The guaranty will expire upon the earlier of the full performance of the guaranteed obligations or December 31, 2021.

(2) Surety bond expiration dates reflect termination dates, the majority of which will be renewed or extended. Certain surety bonds contain credit ratings triggers that would require Eversource parent to post collateral in the event that the unsecured debt credit ratings of Eversource parent are downgraded.

As described in Note 1K, "Investments," Eversource parent issued a guaranty on behalf of its subsidiary, Eversource Investment LLC. Eversource parent will guarantee, as a primary obligor, the financial obligations, primarily all post-Closing payment obligations of Eversource Investment LLC, under the Sale and Purchase Agreement and an Irrevocable Equity Commitment Letter with Ørsted in an amount not to exceed $127.6 million. Eversource parent's obligations under the guaranty expire upon the full, final and indefeasible payment of the guaranteed obligations.

E. FERC ROE Complaints

Four separate complaints have been filed at the FERC by combinations of New England state attorneys general, state regulatory commissions, consumer advocates, consumer groups, municipal parties and other parties (collectively the "Complainants"). In each of the first three complaints, filed on October 1, 2011, December 27, 2012, and July 31, 2014, respectively, the Complainants challenged the NETOs' base ROE of 11.14 percent that had been utilized since 2005 and sought an order to reduce it prospectively from the date of the final FERC order and for the separate 15-month complaint periods. In the fourth complaint, filed April 29, 2016, the Complainants challenged the NETOs' base ROE billed of 10.57 percent and the maximum ROE for transmission incentive ("incentive cap") of 11.74 percent, asserting that these ROEs were unjust and unreasonable.

The ROE originally billed during the period October 1, 2011 (beginning of the first complaint period) through October 15, 2014 consisted of a base ROE of 11.14 percent and incentives up to 13.1 percent. On October 16, 2014, the FERC set the base ROE at 10.57 percent and the incentive cap at 11.74 percent for the first complaint period. This was also effective for all prospective billings to customers beginning October 16, 2014. This FERC order was vacated on April 14, 2017 by the U.S. Court of Appeals for the D.C. Circuit (the "Court").

All amounts associated with the first complaint period have been refunded, which totaled $38.9 million (pre-tax and excluding interest) at Eversource and reflected both the base ROE and incentive cap prescribed by the FERC order. The refund consisted of $22.4 million for CL&P, $13.7 million for NSTAR Electric and $2.8 million for PSNH.

Eversource has recorded a reserve of $39.1 million (pre-tax and excluding interest) for the second complaint period as of December 31, 2018. This reserve represents the difference between the billed rates during the second complaint period and a 10.57 percent base ROE and 11.74 percent incentive cap. The reserve consisted of $21.4 million for CL&P, $14.6 million for NSTAR Electric and $3.1 million for PSNH as of December 31, 2018.

On October 16, 2018, FERC issued an order on all four complaints describing how it intends to address the issues that were remanded by the Court. FERC proposed a new framework to determine (1) whether an existing ROE is unjust and unreasonable and, if so, (2) how to calculate a replacement ROE. The parties to these proceedings were directed to submit briefs on this new proposed framework and how they would apply the proposed framework in each of the four complaint proceedings. Initial briefs were filed by the NETOs, Complainants and FERC Trial Staff on January 11, 2019. The NETOs' brief was supportive of the overall ROE methodology determined in the October 16, 2018 order providing the FERC does not change the proposed methodology or alter its implementation in a manner that has a material impact on the results. Reply briefs will be filed on March 8, 2019.

The FERC order included illustrative calculations for the first complaint using FERC's proposed frameworks with financial data from that complaint. Those preliminary calculations indicated that for the first complaint period, for the NETOs that FERC concludes are of average financial risk, (1) a preliminary range of presumptively just and reasonable base ROEs is 9.60 percent to 10.99 percent; (2) the pre-existing base ROE of 11.14 percent is therefore unjust and unreasonable; (3) the preliminary just and reasonable base ROE is 10.41 percent; and (4) the preliminary incentive cap on total ROE is 13.08 percent.

If the results of these illustrative calculations were included in a final FERC order for each of the complaint periods, then a 10.41 percent base ROE and a 13.08 percent incentive cap would not have a significant impact on our financial statements for all of the complaint periods.

Although the order provided illustrative calculations, FERC stated that these calculations are merely preliminary. The FERC's preliminary calculations are not binding and do not represent what we believe to be the most likely outcome of a final FERC order, as changes to the methodology by FERC are possible as a result of the parties' arguments and calculations in the briefing process. Until FERC issues a final decision on each of these four complaints, there is significant uncertainty, and at this time, the Company cannot reasonably estimate a range of gain or loss for any of the four complaint proceedings. The October 16, 2018 FERC order or the January 11, 2019 briefs did not provide a reasonable basis for a change to the reserve or recognized ROEs for any of the complaint periods.

Eversource, CL&P, NSTAR Electric and PSNH currently record revenues at the 10.57 percent base ROE and incentive cap at 11.74 percent established in the October 16, 2014 FERC order.

The average impact of a 10 basis point change to the base ROE for each of the 15-month complaint periods would affect Eversource's after-tax earnings by approximately $3 million.

F. Eversource and NSTAR Electric Boston Harbor Civil Action

On July 15, 2016, the United States Attorney on behalf of the United States Army Corps of Engineers filed a civil action in the United States District Court for the District of Massachusetts under provisions of the Rivers and Harbors Act of 1899 and the Clean Water Act against NSTAR Electric, Harbor Electric Energy Company, a wholly-owned subsidiary of NSTAR Electric ("HEEC"), and the Massachusetts Water Resources Authority (together with NSTAR Electric and HEEC, the "Defendants"). The action alleged that the Defendants failed to comply with certain permitting

requirements related to the placement of the HEEC-owned electric distribution cable beneath Boston Harbor. The action sought an order to compel HEEC to comply with cable depth requirements in the United States Army Corps of Engineers' permit or alternatively to remove the electric distribution cable and cease unauthorized work in U.S. waterways. The action also sought civil penalties and other costs.

The parties reached a settlement pursuant to which HEEC agreed to install a new 115kV distribution cable across Boston Harbor to Deer Island, utilizing a different route, and remove portions of the existing cable. Upon the installation and completion of the new cable and the removal of the portions of the existing cable, all issues surrounding the current permit from the United States Army Corps of Engineers are expected to be resolved, and such litigation is expected to be dismissed with prejudice.

In 2017, as a result of the settlement, NSTAR Electric expensed $4.9 million (pre-tax) of previously incurred capitalized costs associated with engineering work performed on the existing cable that will no longer be used. In addition, NSTAR Electric agreed to provide a rate base credit of $17.5 million to the Massachusetts Water Resources Authority for the new cable. This negotiated credit resulted in the initial $17.5 million of construction costs on the new cable being expensed as incurred, all of which was fully expensed by the end of 2018. Construction of the new cable is underway and is expected to be completed in 2019.

G. Litigation and Legal Proceedings

Eversource, including CL&P, NSTAR Electric and PSNH, are involved in legal, tax and regulatory proceedings regarding matters arising in the ordinary course of business, which involve management's assessment to determine the probability of whether a loss will occur and, if probable, its best estimate of probable loss. The Company records and discloses losses when these losses are probable and reasonably estimable, and discloses matters when losses are probable but not estimable or when losses are reasonably possible. Legal costs related to the defense of loss contingencies are expensed as incurred.

13. GENERATION ASSET SALE

In June 2015, Eversource and PSNH entered into the 2015 Public Service Company of New Hampshire Restructuring and Rate Stabilization Agreement, pursuant to which PSNH agreed to divest its generation assets, subject to NHPUC approval. The NHPUC approved this agreement as well as the final divestiture plan and auction process in 2016. On October 11, 2017, PSNH entered into two Purchase and Sale Agreements with private investors, one to sell its thermal generation assets at a purchase price of $175 million, subject to adjustment, (the “Thermal Agreement”) and a second to sell its hydroelectric generation assets at a purchase price of $83 million, subject to adjustment (the “Hydro Agreement”). The NHPUC approved these agreements in late November 2017, at which time the Company classified these assets as held for sale.

On January 10, 2018, PSNH completed the sale of its thermal generation assets pursuant to the Thermal Agreement. In accordance with the Thermal Agreement, the original purchase price of $175 million was adjusted to reflect working capital adjustments, closing date adjustments and proration of taxes and fees prior to closing, totaling $40.9 million. In the second quarter of 2018, the purchase price was further adjusted by $17.3 million relating to the valuation of certain allowances. As a result of these adjustments, net proceeds from the sale of the thermal assets totaled $116.8 million.

On July 16, 2018, FERC issued its order approving the transfer of PSNH's six hydroelectric licenses to private investors. On August 26, 2018, PSNH completed the sale of its hydroelectric generation assets pursuant to the Hydro Agreement. In accordance with the Hydro Agreement, the original purchase price of $83 million was adjusted to reflect contractual adjustments totaling $5.8 million, resulting in net proceeds of $77.2 million. The difference between the carrying value of the hydroelectric generation assets and the sale proceeds resulted in a gain of $17.3 million. An estimated gain from the sale of these assets was included as an offset to the total remaining costs associated with the sale of generation assets that were securitized on May 8, 2018.

On May 8, 2018, PSNH Funding issued $635.7 million of securitized RRBs to finance PSNH's unrecovered remaining costs associated with the divestiture of its generation assets, which included the deferred costs resulting from the sale of the thermal generation assets. These RRBs are secured by a non-bypassable charge recoverable from PSNH customers. As of December 31, 2018, unamortized securitized stranded costs totaled $608.4 million and are included in Regulatory Assets on the Eversource and PSNH balance sheets. As of December 31, 2017, the deferred costs resulting from the thermal generation asset sale of $516.1 million represented the difference between the carrying value and the fair value less cost to

sell the thermal generation assets. For further information on the securitized RRB issuance, see Note 9, "Rate Reduction Bonds and Variable Interest Entities."

For the year ended December 31, 2018, pre-tax income associated with the hydroelectric assets prior to the sale on August 26, 2018 was $9.9 million. For the years ended December 31, 2017 and 2016, pre-tax income associated with PSNH's generation assets was $60.0 million, and $65.3 million, respectively.

As of December 31, 2018, all generation assets had been sold and as a result, no generation assets were classified as held for sale. As of December 31, 2017, PSNH's generation assets held for sale, which were included in current assets on the Eversource and PSNH balance sheets, and were part of the Electric Distribution reportable segment, were as follows:

(Millions of Dollars)	As of December 31, 2017
Thermal Gross Plant	$ 1,091.4
Hydroelectric Gross Plant	83.0
Accumulated Depreciation	(575.4)
Net Plant	599.0
Fuel and Inventory	87.7
Materials and Supplies	27.3
Emission Allowances	19.1
Other Assets	2.6
Deferred Costs from Thermal Generation Asset Sale	(516.1)
Total Generation Assets Held for Sale	$ 219.6

14. LEASES

Eversource, including CL&P, NSTAR Electric and PSNH, has entered into lease agreements, some of which are capital leases, for the use of land, office space, service centers, vehicles, information technology, and office equipment. In addition, CL&P, NSTAR Electric and PSNH incur costs associated with leases entered into by affiliated Eversource subsidiaries, including Eversource Service and Rocky River Realty Company, and are included below in their respective operating lease rental expenses and future minimum rental payments. These intercompany lease amounts are eliminated on an Eversource consolidated basis. The provisions of the Eversource, CL&P, NSTAR Electric and PSNH lease agreements generally contain renewal options. One lease agreement contains payments impacted by the consumer price index.

Operating lease rental payments charged to expense are as follows:

(Millions of Dollars)	Eversource	CL&P	NSTAR Electric	PSNH
2018	$ 10.8	$ 10.9	$ 11.8	$ 2.5
2017	10.5	11.7	11.3	3.3
2016	12.1	12.5	11.4	2.9

Future minimum rental payments, excluding executory costs, such as property taxes, state use taxes, insurance, and maintenance, under long-term non-cancelable leases, as of December 31, 2018 are as follows:

Operating Leases *(Millions of Dollars)*	**Eversource**	**CL&P**	**NSTAR Electric**	**PSNH**
2019	$ 11.5	$ 1.5	$ 7.2	$ 0.5
2020	9.8	1.4	6.0	0.4
2021	8.7	1.2	5.3	0.4
2022	7.2	1.1	4.4	0.4
2023	4.7	0.5	3.1	0.2
Thereafter	32.7	0.2	29.5	0.3
Future minimum lease payments	$ 74.6	$ 5.9	$ 55.5	$ 2.2

Capital Leases *(Millions of Dollars)*	**Eversource**	**CL&P**	**NSTAR Electric**	**PSNH**
2019	$ 3.4	$ 2.0	$ 0.5	$ 0.1
2020	3.4	2.0	0.5	0.1
2021	2.9	1.5	0.5	0.1
2022	1.5	—	0.6	0.1
2023	0.7	—	0.6	0.1
Thereafter	13.9	—	13.4	0.5
Future minimum lease payments	25.8	5.5	16.1	1.0
Less amount to arrive at present value	13.8	1.0	12.4	0.1
Present value of future minimum lease payments	$ 12.0	$ 4.5	$ 3.7	$ 0.9

CL&P and PSNH entered into certain contracts for the purchase of energy that qualify as leases. These contracts do not have minimum lease payments and therefore are not included in the tables above. However, such contracts and corresponding expense have been included in the contractual obligations tables in Note 12B, "Commitments and Contingencies - Long-Term Contractual Arrangements," to the financial statements.

15. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each of the following financial instruments:

Preferred Stock, Long-Term Debt and Rate Reduction Bonds: The fair value of CL&P's and NSTAR Electric's preferred stock is based upon pricing models that incorporate interest rates and other market factors, valuations or trades of similar securities and cash flow projections. The fair value of long-term debt and RRB debt securities is based upon pricing models that incorporate quoted market prices for those issues or similar issues adjusted for market conditions, credit ratings of the respective companies and treasury benchmark yields. The fair values provided in the table below are classified as Level 2 within the fair value hierarchy. Carrying amounts and estimated fair values are as follows:

	Eversource		CL&P		NSTAR Electric		PSNH	
(Millions of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
As of December 31, 2018:								
Preferred Stock Not Subject to Mandatory Redemption	$ 155.6	$ 156.8	$ 116.2	$ 113.8	$ 43.0	$ 43.0	$ —	$ —
Long-Term Debt	13,086.1	13,154.9	3,254.0	3,429.2	2,944.8	3,024.1	805.2	819.5
Rate Reduction Bonds	635.7	645.8	—	—	—	—	635.7	645.8
As of December 31, 2017:								
Preferred Stock Not Subject to Mandatory Redemption	$ 155.6	$ 160.8	$ 116.2	$ 116.5	$ 43.0	$ 44.3	$ —	$ —
Long-Term Debt	12,325.5	12,877.1	3,059.1	3,430.5	2,943.8	3,156.5	1,002.4	1,038.2

Derivative Instruments and Marketable Securities: Derivative instruments and investments in marketable securities are carried at fair value. For further information, see Note 4, "Derivative Instruments," and Note 5, "Marketable Securities," to the financial statements.

See Note 1I, "Summary of Significant Accounting Policies – Fair Value Measurements," for the fair value measurement policy and the fair value hierarchy.

16. ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

The changes in accumulated other comprehensive income/(loss) by component, net of tax, are as follows:

	For the Year Ended December 31, 2018				For the Year Ended December 31, 2017			
Eversource *(Millions of Dollars)*	Qualified Cash Flow Hedging Instruments	Unrealized Losses on Marketable Securities	Defined Benefit Plans	Total	Qualified Cash Flow Hedging Instruments	Unrealized Gains/(Losses) on Marketable Securities	Defined Benefit Plans	Total
Balance as of January 1st	$ (6.2)	$ —	$ (60.2)	$ (66.4)	$ (8.2)	$ 0.4	$ (57.5)	$ (65.3)
OCI Before Reclassifications	—	(0.5)	0.3	(0.2)	—	(0.4)	(7.2)	(7.6)
Amounts Reclassified from AOCI	1.8	—	4.8	6.6	2.0	—	4.5	6.5
Net OCI	1.8	(0.5)	5.1	6.4	2.0	(0.4)	(2.7)	(1.1)
Balance as of December 31st	$ (4.4)	$ (0.5)	$ (55.1)	$ (60.0)	$ (6.2)	$ —	$ (60.2)	$ (66.4)

Eversource's qualified cash flow hedging instruments represent interest rate swap agreements on debt issuances that were settled in prior years. The settlement amount was recorded in AOCI and is being amortized into Net Income over the term of the underlying debt instrument. CL&P, NSTAR Electric and PSNH continue to amortize interest rate swaps settled in prior years from AOCI into Interest Expense over the remaining life of the associated long-term debt. Such interest rate swaps are not material to their respective financial statements.

Defined benefit plan OCI amounts before reclassifications relate to actuarial gains and losses that arose during the year and were recognized in AOCI. The unamortized actuarial gains and losses and prior service costs on the defined benefit plans are amortized from AOCI into Other Income, Net over the average future employee service period, and are reflected in amounts reclassified from AOCI. The related tax effects recognized in AOCI were net deferred tax liabilities of $0.2 million in 2018, and deferred tax assets of $4.1 million and $4.0 million in 2017 and 2016, respectively.

The following table sets forth the amounts reclassified from AOCI by component and the impacted line item on the statements of income:

Eversource *(Millions of Dollars)*	Amounts Reclassified from AOCI For the Years Ended December 31, 2018	2017	2016	Statements of Income Line Item Impacted
Qualified Cash Flow Hedging Instruments	$ (2.8)	$ (3.3)	$ (3.5)	Interest Expense
Tax Effect	1.0	1.3	1.4	Income Tax Expense
Qualified Cash Flow Hedging Instruments, Net of Tax	$ (1.8)	$ (2.0)	$ (2.1)	
Defined Benefit Plan Costs:				
Amortization of Actuarial Losses	$ (6.0)	$ (6.2)	$ (5.6)	Other Income, Net (1)
Amortization of Prior Service Cost	(0.4)	(1.1)	(0.8)	Other Income, Net (1)
Total Defined Benefit Plan Costs	(6.4)	(7.3)	(6.4)	
Tax Effect	1.6	2.8	2.5	Income Tax Expense
Defined Benefit Plan Costs, Net of Tax	$ (4.8)	$ (4.5)	$ (3.9)	
Total Amounts Reclassified from AOCI, Net of Tax	$ (6.6)	$ (6.5)	$ (6.0)	

(1) These amounts are included in the computation of net periodic Pension, SERP and PBOP costs. See Note 1N, "Summary of Significant Accounting Policies – Other Income, Net" and Note 10A, "Employee Benefits – Pension Benefits and Postretirement Benefits Other Than Pension," for further information.

As of December 31, 2018, it is estimated that a pre-tax amount of $2.5 million ($0.7 million for NSTAR Electric and $1.8 million for PSNH) will be reclassified from AOCI as a decrease to Net Income over the next 12 months as a result of the amortization of the interest rate swap agreements which have been settled. In addition, it is estimated that a pre-tax amount of $6.3 million will be reclassified from AOCI as a decrease to Net Income over the next 12 months as a result of the amortization of Pension, SERP and PBOP costs.

17. DIVIDEND RESTRICTIONS

Eversource parent's ability to pay dividends may be affected by certain state statutes, the ability of its subsidiaries to pay common dividends and the leverage restriction tied to its consolidated total debt to total capitalization ratio requirement in its revolving credit agreement. Pursuant to the joint revolving credit agreement of Eversource, CL&P, PSNH, Yankee Gas and NSTAR Gas, and to the NSTAR Electric revolving credit agreement, each company is required to maintain consolidated total indebtedness to total capitalization ratio of no greater than 65 percent at the end of each fiscal quarter. As of December 31, 2018, all companies were in compliance with such covenant. Eversource, CL&P, NSTAR Electric, PSNH, Yankee Gas and NSTAR Gas were in compliance with all such provisions of the revolving credit agreements that may restrict the payment of dividends as of December 31, 2018.

The Retained Earnings balances subject to dividend restrictions were $4.0 billion for Eversource, $1.7 billion for CL&P, $2.1 billion for NSTAR Electric and $627.3 million for PSNH as of December 31, 2018.

CL&P, NSTAR Electric and PSNH are subject to Section 305 of the Federal Power Act that makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in its capital account." Management believes that this Federal Power Act restriction, as applied to CL&P, NSTAR Electric and PSNH, would not be construed or applied by the FERC to prohibit the payment of dividends from retained earnings for lawful and legitimate business purposes. In addition, certain state statutes may impose additional limitations on such companies and on Yankee Gas and NSTAR Gas. Such state law restrictions do not restrict the payment of dividends from retained earnings or net income.

18. COMMON SHARES

The following table sets forth the Eversource parent common shares and the shares of common stock of CL&P, NSTAR Electric and PSNH that were authorized and issued, as well as the respective per share par values:

	Shares			
	Par Value	Authorized as of December 31, 2018 and 2017	Issued as of December 31,	
			2018	2017
Eversource	$ 5	380,000,000	333,878,402	333,878,402
CL&P	$ 10	24,500,000	6,035,205	6,035,205
NSTAR Electric	$ 1	100,000,000	200	200
PSNH	$ 1	100,000,000	301	301

As of both December 31, 2018 and 2017, there were 16,992,594 Eversource common shares held as treasury shares. As of both December 31, 2018 and 2017, there were 316,885,808 Eversource common shares outstanding.

19. PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION

The CL&P and NSTAR Electric preferred stock is not subject to mandatory redemption and is presented as a noncontrolling interest of a subsidiary in Eversource's financial statements.

CL&P is authorized to issue up to 9,000,000 shares of preferred stock, par value $50 per share, and NSTAR Electric is authorized to issue 2,890,000 shares of preferred stock, par value $100 per share. Holders of preferred stock of CL&P and NSTAR Electric are entitled to receive cumulative dividends in preference to any payment of dividends on the common stock. Upon liquidation, holders of preferred stock of CL&P and NSTAR Electric are entitled to receive a liquidation preference before any distribution to holders of common stock in an amount equal to the par value of the preferred stock plus accrued and unpaid dividends. If the net assets were to be insufficient to pay the liquidation preference in full, then the net assets would be distributed ratably to all holders of preferred stock. The preferred stock of CL&P and NSTAR Electric is subject to optional redemption by the CL&P and NSTAR Electric Board of Directors at any time.

Details of preferred stock not subject to mandatory redemption are as follows (in millions, except in redemption price and shares):

Series		Redemption Price Per Share	Shares Outstanding as of December 31,		As of December 31,	
			2018	2017	2018	2017
CL&P						
$1.90	Series of 1947	$ 52.50	163,912	163,912	$ 8.2	$ 8.2
$2.00	Series of 1947	$ 54.00	336,088	336,088	16.8	16.8
$2.04	Series of 1949	$ 52.00	100,000	100,000	5.0	5.0
$2.20	Series of 1949	$ 52.50	200,000	200,000	10.0	10.0
3.90%	Series of 1949	$ 50.50	160,000	160,000	8.0	8.0
$2.06	Series E of 1954	$ 51.00	200,000	200,000	10.0	10.0
$2.09	Series F of 1955	$ 51.00	100,000	100,000	5.0	5.0
4.50%	Series of 1956	$ 50.75	104,000	104,000	5.2	5.2
4.96%	Series of 1958	$ 50.50	100,000	100,000	5.0	5.0
4.50%	Series of 1963	$ 50.50	160,000	160,000	8.0	8.0
5.28%	Series of 1967	$ 51.43	200,000	200,000	10.0	10.0
$3.24	Series G of 1968	$ 51.84	300,000	300,000	15.0	15.0
6.56%	Series of 1968	$ 51.44	200,000	200,000	10.0	10.0
Total CL&P			2,324,000	2,324,000	$ 116.2	$ 116.2
NSTAR Electric						
4.25%	Series of 1956	$ 103.625	180,000	180,000	$ 18.0	$ 18.0
4.78%	Series of 1958	$ 102.80	250,000	250,000	25.0	25.0
Total NSTAR Electric			430,000	430,000	$ 43.0	$ 43.0
Fair Value Adjustment due to Merger with NSTAR					(3.6)	(3.6)
Other						
6.00%	Series of 1958	$ 100.00	23	23	$ —	$ —
Total Eversource - Preferred Stock of Subsidiaries					$ 155.6	$ 155.6

20. COMMON SHAREHOLDERS' EQUITY AND NONCONTROLLING INTERESTS

Dividends on the preferred stock of CL&P and NSTAR Electric totaled $7.5 million for each of the years ended December 31, 2018, 2017 and 2016. These dividends were presented as Net Income Attributable to Noncontrolling Interests on the Eversource statements of income. Noncontrolling Interest – Preferred Stock of Subsidiaries on the Eversource balance sheets totaled $155.6 million as of December 31, 2018 and 2017. On the Eversource balance sheets, Common Shareholders' Equity was fully attributable to Eversource parent and Noncontrolling Interest – Preferred Stock of Subsidiaries was fully attributable to the noncontrolling interest.

For the years ended December 31, 2018, 2017 and 2016, there was no change in ownership of the common equity of CL&P and NSTAR Electric.

21. EARNINGS PER SHARE

Basic EPS is computed based upon the weighted average number of common shares outstanding during each period. Diluted EPS is computed on the basis of the weighted average number of common shares outstanding plus the potential dilutive effect of certain share-based compensation awards as if they were converted into common shares. The dilutive effect of unvested RSU and performance share awards is calculated using the treasury stock method. RSU and performance share awards are included in basic weighted average common shares outstanding as of the date that all necessary vesting conditions have been satisfied.

The following table sets forth the components of basic and diluted EPS:

Eversource *(Millions of Dollars, except share information)*	**For the Years Ended December 31,**		
	2018	**2017**	**2016**
Net Income Attributable to Common Shareholders	$ 1,033.0	$ 988.0	$ 942.3
Weighted Average Common Shares Outstanding:			
Basic	317,370,369	317,411,097	317,650,180
Dilutive Effect	623,565	620,483	804,059
Diluted	317,993,934	318,031,580	318,454,239
Basic EPS	$ 3.25	$ 3.11	$ 2.97
Diluted EPS	$ 3.25	$ 3.11	$ 2.96

22. REVENUES

On January 1, 2018, Eversource, including CL&P, NSTAR Electric and PSNH, adopted ASU 2014-09, "*Revenue from Contracts with Customers (Topic 606)*" using the modified retrospective approach. The core principle of this accounting guidance is that revenue is recognized when promised goods or services (referred to as performance obligations) are transferred to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The new standard uses a five-step model for recognizing and measuring revenue from contracts with customers, which includes identifying the contract with the customer, identifying the performance obligations promised within the contract, determining the transaction price (the amount of consideration to which the company expects to be entitled), allocating the transaction price to the performance obligations and recognizing revenue when (or as) the performance obligation is satisfied.

The following table presents operating revenues disaggregated by revenue source:

	For the Year Ended December 31, 2018						
Eversource *(Millions of Dollars)*	**Electric Distribution**	**Natural Gas Distribution**	**Electric Transmission**	**Water Distribution**	**Other**	**Eliminations**	**Total**
Revenue from Contracts with Customers							
Retail Tariff Sales							
Residential	$ 3,766.6	$ 542.5	$ —	$ 130.7	$ —	$ —	$ 4,439.8
Commercial	2,634.7	334.8	—	63.3	—	(4.5)	3,028.3
Industrial	351.9	96.0	—	4.4	—	(10.0)	442.3
Total Retail Tariff Sales Revenue	6,753.2	973.3	—	198.4	—	(14.5)	7,910.4
Wholesale Transmission Revenue	—	—	1,308.9	—	47.3	(1,092.2)	264.0
Wholesale Market Sales Revenue	179.5	57.5	—	4.1	—	—	241.1
Other Revenue from Contracts with Customers	65.9	(2.2)	12.6	7.2	889.0	(891.0)	81.5
Reserve for Revenue Subject to Refund	(12.3)	(8.3)	—	(3.7)	—	—	(24.3)
Total Revenue from Contracts with Customers	6,986.3	1,020.3	1,321.5	206.0	936.3	(1,997.7)	8,472.7
Alternative Revenue Programs	(47.0)	(1.2)	(35.2)	5.4	—	31.9	(46.1)
Other Revenue	17.9	3.1	—	0.6	—	—	21.6
Total Operating Revenues	$ 6,957.2	$ 1,022.2	$ 1,286.3	$ 212.0	$ 936.3	$ (1,965.8)	$ 8,448.2

	For the Year Ended December 31, 2018		
(Millions of Dollars)	**CL&P**	**NSTAR Electric**	**PSNH**
Revenue from Contracts with Customers			
Retail Tariff Sales			
Residential	$ 1,828.2	$ 1,380.9	$ 557.5
Commercial	928.1	1,391.5	316.9
Industrial	147.7	124.9	79.3
Total Retail Tariff Sales Revenue	2,904.0	2,897.3	953.7
Wholesale Transmission Revenue	620.6	488.8	199.5
Wholesale Market Sales Revenue	48.3	76.1	56.6
Other Revenue from Contracts with Customers	35.0	28.9	15.5
Reserve for Revenue Subject to Refund	—	—	(12.3)
Total Revenue from Contracts with Customers	3,607.9	3,491.1	1,213.0
Alternative Revenue Programs	(65.9)	0.9	(17.3)
Other Revenue	8.5	8.3	1.1
Eliminations	(454.3)	(387.4)	(149.2)
Total Operating Revenues	$ 3,096.2	$ 3,112.9	$ 1,047.6

Retail Tariff Sales: Regulated utilities provide products and services to their regulated customers under rates, pricing, payment terms and conditions of service, regulated by each state regulatory agency. The arrangement whereby a utility provides commodity service to a customer for a price approved by the respective state regulatory commission is referred to as a tariff sale contract, and the tariff governs all aspects of the provision of

regulated services by utilities. The majority of revenue for Eversource, CL&P, NSTAR Electric and PSNH is derived from regulated retail tariff sales for the sale and distribution of electricity, natural gas and water to residential, commercial and industrial retail customers.

The utility's performance obligation for the regulated tariff sales is to provide electricity, natural gas or water to the customer as demanded. The promise to provide the commodity represents a single performance obligation, as it is a promise to transfer a series of distinct goods or services that are substantially the same and that have the same pattern of transfer to the customer. Revenue is recognized over time as the customer simultaneously receives and consumes the benefits provided by the utility, and the utility satisfies its performance obligation. Revenue is recognized based on the output method as there is a directly observable output to the customer (electricity, natural gas or water units delivered to the customer and immediately consumed). Each Eversource utility is entitled to be compensated for performance completed to date (service taken by the customer) until service is terminated.

In regulated tariff sales, the transaction prices are the rates approved by the respective state regulatory commissions. In general, rates can only be changed through formal proceedings with the state regulatory commissions. These rates are designed to recover the costs to provide service to customers and include a return on investment. Regulatory commission-approved tracking mechanisms are included in these rates and are also used to recover, on a fully-reconciling basis, certain costs, such as the procurement of energy supply, retail transmission charges, energy efficiency program costs, net metering for distributed generation, and restructuring and stranded costs. These tracking mechanisms result in rates being changed periodically to ensure recovery of actual costs incurred.

Customers may elect to purchase electricity from each Eversource electric utility or may contract separately with a competitive third party supplier. Revenue is not recorded for the sale of the electricity commodity to customers who have contracted separately with these suppliers, only the delivery to a customer, as the utility is acting as an agent on behalf of the third party supplier.

Wholesale Transmission Revenues: The Eversource electric transmission-owning companies (CL&P, NSTAR Electric and PSNH) each own and maintain transmission facilities that are part of an interstate power transmission grid over which electricity is transmitted throughout New England. CL&P, NSTAR Electric and PSNH, as well as most other New England utilities, are parties to a series of agreements that provide for coordinated planning and operation of the region's transmission facilities and the rules by which they acquire transmission services. The Eversource electric transmission-owning companies have a combination of FERC-approved regional and local formula rates that work in tandem to recover all their transmission costs. These rates are part of the ISO-NE Tariff. Regional rates recover the costs of higher voltage transmission facilities that benefit the region and are collected from all New England transmission customers, including the Eversource distribution businesses. Eversource's local rates recover the companies' total transmission revenue requirements, less revenues received from regional rates and other sources, and are collected from Eversource's distribution businesses and other transmission customers. The distribution businesses of Eversource, in turn, recover the FERC approved charges from retail customers through annual or semiannual tracking mechanisms, which are retail tariff sales.

The utility's performance obligation for regulated wholesale transmission sales is to provide transmission services to the customer as demanded. The promise to provide transmission service represents a single performance obligation. The transaction prices are the transmission rate formulas as defined by the ISO-NE Tariff and are regulated and established by FERC. Wholesale transmission revenue is recognized over time as the performance obligation is completed, which occurs as transmission services are provided to customers. The revenue is recognized based on the output method. Each Eversource utility is entitled to be compensated for performance completed to date (e.g., use of the transmission system by the customer).

Wholesale Market Sales Revenues: Wholesale market sales transactions include sales of energy and energy-related products into the ISO-NE wholesale electricity market, sales of natural gas to third party marketers, and also the sale of RECs to various counterparties. ISO-NE oversees the region's wholesale electricity market and administers the transactions and terms and conditions, including payment terms, which are established in the ISO-NE tariff, between the buyers and sellers in the market. Pricing is set by the wholesale market. The wholesale transactions in the ISO-NE market occur on a day-ahead basis or a real-time basis (daily) and are, therefore, short-term. Transactions are tracked and reported by ISO-NE net by the hour, which is the net hourly position of energy sales and purchases by each market participant. Beginning in the first quarter of 2018, the performance obligation for ISO-NE energy transactions is defined to be the net by hour transaction. Revenue is recognized when the performance obligation for these energy sales transactions is satisfied, when the sale occurs and the energy is transferred to the customer. For sales of natural gas, transportation, and natural gas pipeline capacity to third party marketers, revenue is recognized when the performance obligation is satisfied at the point in time the sale occurs and the natural gas or related product is transferred to the marketer. RECs are sold to various counterparties, and revenue is recognized when the performance obligation is satisfied upon transfer of title to the customer through the New England Power Pool Generation Information System.

Other Revenue from Contracts with Customers: Other revenue from contracts with customers primarily includes property rentals that are not deemed leases. These revenues are generally recognized on a straight-line basis over time as the service is provided to the customer.

Reserve for Revenue Subject to Refund: Current base rates include an estimate of income taxes, which was based on the U.S. federal corporate income tax rate in effect at the time of the rate proceeding. Eversource established a regulatory liability, recorded as a reduction to revenue, to reflect the difference between the 35 percent federal corporate income tax rate included in rates charged to customers and the 21 percent federal corporate income tax rate, effective January 1, 2018 as a result of the Tax Cuts and Jobs Act, until rates billed to customers reflect the lower federal tax rate. Effective May 1, 2018, CL&P adjusted rates billed to customers to reflect the lower federal income tax rate prospectively and, as of December 31, 2018, fully refunded its regulatory liability associated with the higher federal corporate income tax rate billed to customers in the period between January 1, 2018 through April 30, 2018. Effective November 15, 2018, Yankee Gas adjusted distribution rates to reflect the lower federal income tax rate prospectively and to refund its regulatory liability associated with the higher federal corporate income tax rate billed to customers in the period between January 1, 2018 through November 14, 2018. Although Yankee Gas' new rates were effective January 1, 2019, the provisions of the settlement agreement took effect November 15, 2018. For NSTAR Electric and NSTAR Gas, a December 2018 DPU order indicated that the DPU will not require a revision to base rates for any potential refunds associated with the higher federal corporate income tax rate billed to customers in the period between January 1, 2018 to the effective dates of each company's rate changes (effective February 1, 2018 for NSTAR Electric and July 1, 2018 for NSTAR Gas). PSNH and Aquarion will refund the overcollection in distribution rates from January 1, 2018 to customers in a future period. PSNH will adjust distribution rates to reflect the prospective lower federal income tax rate effective July 1, 2019, or earlier if a rate case is filed for rates effective prior to July 1, 2019.

Alternative Revenue Programs: In accordance with accounting guidance for rate-regulated operations, certain of Eversource's utilities' rate making mechanisms qualify as alternative revenue programs ("ARPs") if they meet specified criteria, in which case revenues may be recognized prior to billing based on allowed levels of collection in rates. Eversource's utility companies recognize revenue and record a regulatory asset or liability once the condition or event allowing for the automatic adjustment of future rates occurs. ARP revenues include both the recognition of the deferral adjustment to ARP revenues, when the regulator-specified condition or event allowing for additional billing or refund has occurred, and an equal and offsetting reversal of the ARP deferral to revenues as those amounts are reflected in the price of service in subsequent periods.

Eversource’s ARPs include the revenue decoupling mechanism and the annual reconciliation adjustment to transmission formula rates, described below.

- Certain Eversource electric, natural gas and water companies, including CL&P and NSTAR Electric, have revenue decoupling mechanisms approved by a regulatory commission ("decoupled companies"). Decoupled companies’ distribution revenues are not directly based on sales volumes. The decoupled companies reconcile their annual base distribution rate recovery to pre-established levels of baseline distribution delivery service revenues, with any difference between the allowed level of distribution revenue and the actual amount realized adjusted through subsequent rates.

- The transmission formula rates provide for the annual reconciliation and recovery or refund of estimated costs to actual costs. The

financial impacts of differences between actual and estimated costs are deferred for future recovery from, or refund to, transmission customers. This transmission deferral reconciles billed transmission revenues to the revenue requirement for our transmission businesses.

Other Revenues: Other Revenues include certain fees charged to customers and lease revenue that are not considered revenue from contracts with customers.

Intercompany Eliminations: Intercompany eliminations are primarily related to the Eversource electric transmission revenues that are derived from ISO-NE regional transmission charges to the distribution businesses of CL&P, NSTAR Electric and PSNH that recover the costs of the wholesale transmission business, and revenues from Eversource's service company. Intercompany revenues and expenses between the Eversource wholesale transmission businesses and the Eversource distribution businesses and from Eversource's service company are eliminated in consolidation and included in "Eliminations" in the table above.

Receivables: Receivables, Net on the balance sheet include trade receivables from our retail customers and receivables arising from ISO-NE billing related to wholesale transmission contracts and wholesale market transactions, sales of natural gas and capacity to marketers, sales of RECs, and property rentals. In general, retail tariff customers and wholesale transmission customers are billed monthly and the payment terms are generally due and payable upon receipt of the bill.

Unbilled Revenues: Unbilled Revenues on the balance sheet represent estimated amounts due from retail customers for electricity, natural gas or water delivered to customers but not yet billed. The utility company has satisfied its performance obligation and the customer has received and consumed the commodity as of the balance sheet date, and therefore, the utility company records revenue for those services in the period the services were provided. Only the passage of time is required before the company is entitled to payment for the satisfaction of the performance obligation. Payment from customers is due monthly as services are rendered and amounts are billed. Actual amounts billed to customers when meter readings become available may vary from the estimated amount.

Unbilled revenues are recognized by allocating estimated unbilled sales volumes to the respective customer classes, and then applying an estimated rate by customer class to those sales volumes. Unbilled revenue estimates reflect seasonality, weather, customer usage patterns, customer rates in effect for customer classes, and the timing of customer billing. The companies that have a decoupling mechanism record a regulatory deferral to reflect the actual allowed amount of revenue associated with their respective decoupled distribution rate design.

Practical Expedients: Eversource has elected practical expedients in the accounting guidance that allow the company to record revenue in the amount that the company has a right to invoice, if that amount corresponds directly with the value to the customer of the company's performance to date, and not to disclose related unsatisfied performance obligations. Retail and wholesale transmission tariff sales fall into this category, as these sales are recognized as revenue in the period the utility provides the service and completes the performance obligation, which is the same as the monthly amount billed to customers. There are no other material revenue streams for which Eversource has unsatisfied performance obligations.

23. SEGMENT INFORMATION

Eversource is organized among the Electric Distribution, Electric Transmission, Natural Gas Distribution and Water Distribution reportable segments and Other based on a combination of factors, including the characteristics of each segments' services, the sources of operating revenues and expenses and the regulatory environment in which each segment operates. These reportable segments represent substantially all of Eversource's total consolidated revenues. Revenues from the sale of electricity, natural gas and water primarily are derived from residential, commercial and industrial customers and are not dependent on any single customer. The Electric Distribution reportable segment includes the results of PSNH's generation facilities prior to sales in January and August 2018, and NSTAR Electric's solar power facilities. Eversource's reportable segments are determined based upon the level at which Eversource's chief operating decision maker assesses performance and makes decisions about the allocation of company resources. On December 4, 2017, Eversource acquired Aquarion, which was considered to be a new operating segment, Water Distribution. Though the water distribution segment does not meet quantitative thresholds under the segment reporting accounting guidance, based on qualitative factors including the nature of the water distribution business, Water Distribution was deemed a reportable segment beginning in 2018.

The remainder of Eversource's operations is presented as Other in the tables below and primarily consists of 1) the equity in earnings of Eversource

parent from its subsidiaries and intercompany interest income, both of which are eliminated in consolidation, and interest expense related to the debt of Eversource parent, 2) the revenues and expenses of Eversource Service, most of which are eliminated in consolidation, 3) the operations of CYAPC and YAEC, 4) Eversource Water Ventures, Inc., parent company of Aquarion, and 5) the results of other unregulated subsidiaries, which are not part of its core business. In addition, Other in the tables below includes Eversource parent's equity ownership interests in certain natural gas pipeline projects owned by Enbridge, Inc., the Bay State Wind project, a renewable energy investment fund, and two companies that transmit hydroelectricity imported from the Hydro-Quebec system in Canada. In the ordinary course of business, Yankee Gas and NSTAR Gas purchase natural gas transmission services from the Enbridge, Inc. natural gas pipeline projects described above. These affiliate transaction costs total approximately $62.5 million annually and are classified as Purchased Power, Fuel and Transmission on the Eversource statements of income.

Each of Eversource's subsidiaries, including CL&P, NSTAR Electric and PSNH, has one reportable segment.

The Electric Transmission segment includes a reduction to Operations and Maintenance expense of $27.5 million in 2016 for costs incurred in previous years that was recovered in transmission rates over the period June 1, 2016 through May 31, 2017. These costs were associated with the merger of Northeast Utilities and NSTAR.

Cash flows used for investments in plant included in the segment information below are cash capital expenditures that do not include amounts incurred but not paid, cost of removal, AFUDC related to equity funds, and the capitalized portions of pension and PBOP expense.

Eversource's segment information is as follows:

	For the Year Ended December 31, 2018 (1)						
Eversource *(Millions of Dollars)*	**Electric Distribution**	**Natural Gas Distribution**	**Electric Transmission**	**Water Distribution**	**Other**	**Eliminations**	**Total**
Operating Revenues	$ 6,957.2	$ 1,022.2	$ 1,286.3	$ 212.0	$ 936.3	$ (1,965.8)	$ 8,448.2
Depreciation and Amortization	(671.8)	(75.0)	(231.8)	(46.5)	(49.1)	2.2	(1,072.0)
Other Operating Expenses	(5,548.6)	(787.6)	(375.5)	(99.8)	(831.5)	1,966.7	(5,676.3)
Operating Income	736.8	159.6	679.0	65.7	55.7	3.1	1,699.9
Interest Expense	(202.8)	(44.1)	(120.6)	(34.3)	(129.3)	32.3	(498.8)
Interest Income	18.7	—	2.4	—	30.3	(33.3)	18.1
Other Income/(Loss), Net	67.5	7.1	31.1	(0.4)	1,185.3	(1,180.3)	110.3
Income Tax (Expense)/Benefit	(160.2)	(29.4)	(161.8)	(0.1)	62.5	—	(289.0)
Net Income	460.0	93.2	430.1	30.9	1,204.5	(1,178.2)	1,040.5
Net Income Attributable to Noncontrolling Interests	(4.6)	—	(2.9)	—	—	—	(7.5)
Net Income Attributable to Common Shareholders	$ 455.4	$ 93.2	$ 427.2	$ 30.9	$ 1,204.5	$ (1,178.2)	$ 1,033.0
Total Assets (as of)	$ 21,389.1	$ 3,904.9	$ 10,285.0	$ 2,253.0	$ 17,874.2	$ (17,464.9)	$ 38,241.3
Cash Flows Used for Investments in Plant	$ 961.3	$ 351.5	$ 929.7	$ 102.3	$ 178.6	$ —	$ 2,523.4

Eversource *(Millions of Dollars)*	For the Year Ended December 31, 2017 (2)						
	Electric Distribution	Natural Gas Distribution	Electric Transmission	Water Distribution	Other	Eliminations	Total
Operating Revenues	$ 5,542.9	$ 947.3	$ 1,301.7	$ 15.9	$ 931.0	$ (986.8)	$ 7,752.0
Depreciation and Amortization	(542.6)	(72.9)	(209.4)	(3.7)	(37.4)	2.2	(863.8)
Other Operating Expenses	(4,072.6)	(716.4)	(382.8)	(8.3)	(806.6)	986.7	(5,000.0)
Operating Income	927.7	158.0	709.5	3.9	87.0	2.1	1,888.2
Interest Expense	(186.3)	(43.1)	(115.1)	(3.1)	(90.0)	15.8	(421.8)
Interest Income	7.3	0.1	1.8	0.1	15.7	(16.7)	8.3
Other Income/(Loss), Net	41.6	3.8	27.3	—	1,113.0	(1,086.0)	99.7
Income Tax Expense	(288.3)	(44.2)	(228.7)	(2.1)	(15.5)	(0.1)	(578.9)
Net Income/(Loss)	502.0	74.6	394.8	(1.2)	1,110.2	(1,084.9)	995.5
Net Income Attributable to Noncontrolling Interests	(4.6)	—	(2.9)	—	—	—	(7.5)
Net Income/(Loss) Attributable to Common Shareholders	$ 497.4	$ 74.6	$ 391.9	$ (1.2)	$ 1,110.2	$ (1,084.9)	$ 988.0
Total Assets (as of)	$ 19,250.4	$ 3,595.2	$ 9,401.2	$ 2,182.9	$ 16,220.9	$ (14,430.2)	$ 36,220.4
Cash Flows Used for Investments in Plant	$ 1,020.7	$ 298.2	$ 867.6	$ 16.0	$ 145.6	$ —	$ 2,348.1

Eversource *(Millions of Dollars)*	For the Year Ended December 31, 2016 (2)						
	Electric Distribution	Natural Gas Distribution	Electric Transmission	Water Distribution	Other	Eliminations	Total
Operating Revenues	$ 5,594.3	$ 857.7	$ 1,210.0	$ —	$ 870.4	$ (893.3)	$ 7,639.1
Depreciation and Amortization	(504.7)	(65.3)	(185.8)	—	(33.5)	2.2	(787.1)
Other Operating Expenses	(4,173.0)	(629.0)	(321.3)	—	(779.2)	891.8	(5,010.7)
Operating Income	916.6	163.4	702.9	—	57.7	0.7	1,841.3
Interest Expense	(193.1)	(41.3)	(110.0)	—	(63.5)	6.9	(401.0)
Interest Income	10.0	0.1	1.2	—	7.0	(7.3)	11.0
Other Income, Net	22.7	0.7	17.8	—	1,021.2	(1,008.9)	53.5
Income Tax (Expense)/Benefit	(288.8)	(45.2)	(238.2)	—	16.5	0.7	(555.0)
Net Income	467.4	77.7	373.7	—	1,038.9	(1,007.9)	949.8
Net Income Attributable to Noncontrolling Interests	(4.6)	—	(2.9)	—	—	—	(7.5)
Net Income Attributable to Common Shareholders	$ 462.8	$ 77.7	$ 370.8	$ —	$ 1,038.9	$ (1,007.9)	$ 942.3
Cash Flows Used for Investments in Plant	$ 812.6	$ 255.3	$ 801.0	$ —	$ 108.0	$ —	$ 1,976.9

(1) Effective January 1, 2018, upon implementation of the new revenue accounting guidance, the electric distribution segment is presented gross and intercompany transmission billings are presented in the eliminations column, as Eversource believes that the electric distribution segment acts as a principal, rather than an agent, in its contracts with retail customers. Retail customers contract directly with the electric distribution utility and do not differentiate between distribution and transmission services. Therefore, the electric distribution segment revenues, which are derived from retail customer billings, are presented gross of the eliminations. Prior to 2018, the electric distribution segment presented intercompany electric transmission billings net, based on indicators of net presentation prior to the new revenue guidance. See Note 22 "Revenues," to the financial statements regarding accounting for revenues.

(2) As a result of the adoption of new accounting guidance, the non-service related components of pension, SERP and PBOP benefit costs are presented as non-operating income and recorded in Other Income, Net on the statements of income. The 2017 and 2016 amounts, which were previously presented within Operations and Maintenance expense on the statements of income, have been retrospectively presented within Other Income, Net for the years ended December 31, 2017 and 2016. See Note 1C, "Summary of Significant Accounting Policies - Accounting Standards" and Note 1N, "Summary of Significant Accounting Policies - Other Income, Net," to the financial statements for further information.

(3) The water distribution business was determined to be a reportable segment beginning in 2018. The 2017 segment information has been recast to conform to the current segment reporting structure.

24. ACQUISITION OF AQUARION AND GOODWILL

A. Acquisition of Aquarion

On December 4, 2017, Eversource acquired Aquarion for a purchase price of $1.675 billion, consisting of approximately $880 million in cash and $795 million of assumed Aquarion debt. Aquarion is a holding company that owns three separate regulated water utility subsidiaries engaged in the water collection, treatment and distribution business that operate in Connecticut, Massachusetts and New Hampshire. These regulated utilities collect, treat and distribute water to residential, commercial and industrial customers, to other utilities for resale, and for private and municipal fire protection. Aquarion and its subsidiaries became wholly-owned subsidiaries of Eversource, and Eversource's consolidated financial information includes Aquarion and its subsidiaries' activity beginning December 4, 2017. The approximate $880 million cash purchase price included the $745 million equity purchase price plus a $135 million shareholder loan that was repaid at closing.

Purchase Price Allocation: The purchase price allocation reflects a measurement period adjustment recorded in the first quarter of 2018 to revise the fair value of Aquarion's regulated debt. The $7.9 million increase to the fair value of Long-Term Debt (including the current portion) and corresponding increase to Regulatory Assets, included within Other Noncurrent Assets, excluding Goodwill in the table below, will be amortized over the life of the related debt. The allocation of the cash purchase price was as follows:

Millions of Dollars)		
Current Assets	$	41.2
PP&E		1,034.9
Goodwill		907.9
Other Noncurrent Assets, excluding Goodwill		215.5
Current Liabilities		(121.9)
Noncurrent Liabilities		(421.6)
Long-Term Debt		(778.3)
Total Cash Purchase Price	$	877.7

Pro Forma Financial Information: The following unaudited pro forma financial information reflects the pro forma combined results of operations of Eversource and Aquarion and reflects the amortization of purchase price adjustments assuming the acquisition had taken place on January 1, 2016. The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or the future consolidated results of operations of Eversource.

	For the Years Ended December 31,	
(Pro forma amounts in millions, except share amounts)	**2017**	**2016**
Operating Revenues	$ 7,947.7	$ 7,849.0
Net Income Attributable to Common Shareholders	1,019.1	969.3
Basic EPS	3.21	3.05
Diluted EPS	3.20	3.04

Aquarion Revenues and Pre-Tax Income: The impact of Aquarion on Eversource's accompanying consolidated statement of income included operating revenues of $15.9 million and pre-tax income of $1.1 million for the year ended December 31, 2017.

B. Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Goodwill is evaluated for impairment at least annually and more frequently if indicators of impairment arise. In accordance with the accounting standards, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. Goodwill is not subject to amortization, however is subject to a fair value based assessment for impairment at least annually and whenever facts or circumstances indicate that there may be an impairment. A resulting write-down, if any, would be charged to Operating Expenses.

Eversource completed the acquisition of Aquarion on December 4, 2017, resulting in the addition of $0.9 billion of goodwill. Upon completion of the acquisition, Eversource determined that the reporting units for the purpose of testing goodwill are Electric Distribution, Electric Transmission, Natural Gas Distribution and Water Distribution. The goodwill resulting from the Aquarion acquisition has been entirely allocated to the Water Distribution reporting unit. These reporting units are consistent with the operating segments underlying the reportable segments identified in Note 23, "Segment Information," to the financial statements.

Eversource completed its annual goodwill impairment test for Electric Distribution, Electric Transmission, Natural Gas Distribution and Water Distribution reporting units as of October 1, 2018 and determined that no impairment existed. There were no events subsequent to October 1, 2018 that indicated impairment of goodwill. The annual goodwill assessment included an evaluation of the Company's share price and credit ratings, analyst reports, financial performance, cost and risk factors, long-term strategy, growth and future projections, as well as macroeconomic, industry and market conditions. This evaluation required the consideration of several factors that impact the fair value of the reporting units, including conditions and assumptions that affect the future cash flows of the reporting units. Key considerations include discount rates, utility sector market performance and merger transaction multiples, and internal estimates of future cash flows and net income.

The following table presents goodwill by reportable segment as of December 31, 2018 and 2017:

(Billions of Dollars)	Electric Distribution	Electric Transmission	Natural Gas Distribution	Water Distribution	Total
Goodwill	$ 2.5	$ 0.6	$ 0.4	$ 0.9	$ 4.4

25. QUARTERLY FINANCIAL DATA (UNAUDITED)

Eversource *(Millions of Dollars, except per share information)*	Quarter Ended							
	2018				2017			
	March 31,	June 30,	September 30,	December 31,	March 31,	June 30,	September 30,	December 31,
Operating Revenues	$ 2,288.0	$ 1,853.9	$ 2,271.4	$ 2,034.9	$ 2,105.1	$ 1,762.8	$ 1,988.5	$ 1,895.6
Operating Income	442.5	391.4	466.0	400.0	501.0	448.2	495.3	443.7
Net Income	271.4	244.6	291.3	233.2	261.3	232.6	262.2	239.4
Net Income Attributable to Common Shareholders	269.5	242.8	289.4	231.3	259.5	230.7	260.4	237.4
Basic and Diluted EPS (1)	$ 0.85	$ 0.76	$ 0.91	$ 0.73	$ 0.82	$ 0.73	$ 0.82	$ 0.75

(1) The summation of quarterly EPS data may not equal annual data due to rounding.

(Millions of Dollars)	Quarter Ended							
	2018				2017			
	March 31,	June 30,	September 30,	December 31,	March 31,	June 30,	September 30,	December 31,
CL&P								
Operating Revenues	$ 785.0	$ 694.9	$ 865.0	$ 751.3	$ 732.3	$ 666.6	$ 774.8	$ 713.7
Operating Income	157.2	163.1	172.7	142.8	175.5	175.6	177.1	155.2
Net Income	98.6	99.7	100.3	79.1	90.2	91.3	96.1	99.1
NSTAR Electric								
Operating Revenues	$ 770.1	$ 690.7	$ 939.5	$ 712.6	$ 733.8	$ 704.7	$ 851.9	$ 690.2
Operating Income	119.0	133.6	205.5	126.0	156.6	177.9	229.7	124.2
Net Income	77.1	87.9	140.6	77.5	83.4	95.0	125.8	70.5
PSNH								
Operating Revenues	$ 267.4	$ 235.1	$ 290.2	$ 254.9	$ 253.2	$ 230.4	$ 250.0	$ 248.0
Operating Income	55.8	46.9	56.5	37.2	66.6	63.5	66.0	69.8
Net Income	35.1	25.8	40.7	14.3	34.3	31.6	33.7	36.4

GLOSSARY OF TERMS

The following is a glossary of abbreviations and acronyms that are found in this report:

Current or former Eversource Energy companies, segments or investments:

Eversource, ES or the Company	Eversource Energy and subsidiaries
Eversource parent or ES parent	Eversource Energy, a public utility holding company
ES parent and other companies	ES parent and other companies are comprised of Eversource parent, Eversource Service, Eversource Water Ventures, Inc. (parent company of Aquarion), and other subsidiaries, which primarily includes our unregulated businesses, HWP Company, The Rocky River Realty Company (a real estate subsidiary), the consolidated operations of CYAPC and YAEC, and Eversource parent's equity ownership interests that are not consolidated
CL&P	The Connecticut Light and Power Company
NSTAR Electric	NSTAR Electric Company
PSNH	Public Service Company of New Hampshire
PSNH Funding	PSNH Funding LLC 3, a bankruptcy remote, special purpose, wholly-owned subsidiary of PSNH
NSTAR Gas	NSTAR Gas Company
Yankee Gas	Yankee Gas Services Company
Aquarion	Eversource Aquarion Holdings, Inc. and its subsidiaries (formerly known as Macquarie Utilities Inc)
NPT	Northern Pass Transmission LLC
Northern Pass	The HVDC and associated alternating-current transmission line project from Canada into New Hampshire
Eversource Service	Eversource Energy Service Company
Bay State Wind	A project being developed jointly by Eversource and Denmark-based Ørsted (formerly known as DONG Energy) to construct an offshore wind farm off the coast of Massachusetts
CYAPC	Connecticut Yankee Atomic Power Company
MYAPC	Maine Yankee Atomic Power Company
YAEC	Yankee Atomic Electric Company
Yankee Companies	CYAPC, YAEC and MYAPC
Regulated companies	The Eversource regulated companies are comprised of the electric distribution and transmission businesses of CL&P, NSTAR Electric and PSNH, the natural gas distribution businesses of Yankee Gas and NSTAR Gas, NPT, Aquarion, and the solar power facilities of NSTAR Electric

Regulators:

DEEP	Connecticut Department of Energy and Environmental Protection
DOE	U.S. Department of Energy
DOER	Massachusetts Department of Energy Resources
DPU	Massachusetts Department of Public Utilities
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ISO-NE	ISO New England, Inc., the New England Independent System Operator
MA DEP	Massachusetts Department of Environmental Protection
NHPUC	New Hampshire Public Utilities Commission
PURA	Connecticut Public Utilities Regulatory Authority
SEC	U.S. Securities and Exchange Commission
SJC	Supreme Judicial Court of Massachusetts

Other Terms and Abbreviations:

Access Northeast	A project jointly owned by Eversource, Enbridge, Inc. ("Enbridge"), and National Grid plc ("National Grid") through Algonquin Gas Transmission, LLC ("AGT")
ADIT	Accumulated Deferred Income Taxes
AFUDC	Allowance For Funds Used During Construction
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
Bcf	Billion cubic feet
C&LM	Conservation and Load Management
CfD	Contract for Differences
CTA	Competitive Transition Assessment
CWIP	Construction Work in Progress
EDC	Electric distribution company
EPS	Earnings Per Share
ERISA	Employee Retirement Income Security Act of 1974
ESOP	Employee Stock Ownership Plan
Eversource 2017 Form 10-K	The Eversource Energy and Subsidiaries 2017 combined Annual Report on Form 10-K as filed with the SEC
Fitch	Fitch Ratings
FMCC	Federally Mandated Congestion Charge
FTR	Financial Transmission Rights
GAAP	Accounting principles generally accepted in the United States of America
GSC	Generation Service Charge
GSRP	Greater Springfield Reliability Project
GWh	Gigawatt-Hours
HQ	Hydro-Québec, a corporation wholly-owned by the Québec government, including its divisions that produce, transmit and distribute electricity in Québec, Canada
HVDC	High-voltage direct current
Hydro Renewable Energy	Hydro Renewable Energy, Inc., a wholly-owned subsidiary of Hydro-Québec
IPP	Independent Power Producers
ISO-NE Tariff	ISO-NE FERC Transmission, Markets and Services Tariff
kV	Kilovolt
kVa	Kilovolt-ampere
kW	Kilowatt (equal to one thousand watts)
kWh	Kilowatt-Hours (the basic unit of electricity energy equal to one kilowatt of power supplied for one hour)
LBR	Lost Base Revenue
LNG	Liquefied natural gas
LRS	Supplier of last resort service
MG	Million gallons
MGP	Manufactured Gas Plant
MMBtu	One million British thermal units
MMcf	Million cubic feet
Moody's	Moody's Investors Services, Inc.

MW	Megawatt
MWh	Megawatt-Hours
NEEWS	New England East-West Solution
NETOs	New England Transmission Owners (including Eversource, National Grid and Avangrid)
OCI	Other Comprehensive Income/(Loss)
PAM	Pension and PBOP Rate Adjustment Mechanism
PBOP	Postretirement Benefits Other Than Pension
PBOP Plan	Postretirement Benefits Other Than Pension Plan
PCRBs	Pollution Control Revenue Bonds
Pension Plan	Single uniform noncontributory defined benefit retirement plan
PPA	Pension Protection Act
RRBs	Rate Reduction Bonds
RECs	Renewable Energy Certificates
Regulatory ROE	The average cost of capital method for calculating the return on equity related to the distribution and generation business segment excluding the wholesale transmission segment
RNS	Regional Network Service
ROE	Return on Equity
RRB	Rate Reduction Bond or Rate Reduction Certificate
RSUs	Restricted share units
S&P	Standard & Poor's Financial Services LLC
SBC	Systems Benefits Charge
SCRC	Stranded Cost Recovery Charge
SERP	Supplemental Executive Retirement Plans and non-qualified defined benefit retirement plans
SS	Standard service
TCAM	Transmission Cost Adjustment Mechanism
TSA	Transmission Service Agreement
UI	The United Illuminating Company

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	372,456			
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value	(267,417)			
4	Total (lines 2 and 3)	(267,417)			
5	Balance of Account 219 at End of Preceding Quarter/Year	105,039			
6	Balance of Account 219 at Beginning of Current Year	105,039			
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value	8,181			
9	Total (lines 7 and 8)	8,181			
10	Balance of Account 219 at End of Current Quarter/Year	113,220			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [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	(2,366,468)		(1,994,012)		
2					
3	437,326		169,909		
4	437,326		169,909	374,725,977	374,895,886
5	(1,929,142)		(1,824,103)		
6	(1,929,142)		(1,824,103)		
7					
8	437,326		445,507		
9	437,326		445,507	383,090,152	383,535,659
10	(1,491,816)		(1,378,596)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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)	9,511,356,841	9,511,356,841
4	Property Under Capital Leases	4,342,945	4,342,945
5	Plant Purchased or Sold		
6	Completed Construction not Classified	1,375,372,223	1,375,372,223
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	10,891,072,009	10,891,072,009
9	Leased to Others		
10	Held for Future Use	40,942,311	40,942,311
11	Construction Work in Progress	470,314,379	470,314,379
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	11,402,328,699	11,402,328,699
14	Accum Prov for Depr, Amort, & Depl	2,967,931,831	2,967,931,831
15	Net Utility Plant (13 less 14)	8,434,396,868	8,434,396,868
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,910,139,724	2,910,139,724
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	57,792,107	57,792,107
22	Total In Service (18 thru 21)	2,967,931,831	2,967,931,831
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		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,967,931,831	2,967,931,831

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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
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					31
					32
					33

Schedule Page: 200 Line No.: 13 Column: c

Company	Plant in Service (Line 3)	Property Under Capital Leases (Line 4)	CCNC (Line 6)	Held for Future Use (Line 10)	CWIP (Line 11)	Total (Line 13)
East	7,612,055,773	4,342,945	965,785,442	40,774,950	427,941,342	9,050,900,451
West Distribution	920,077,185	-	113,137,093	167,361	23,136,976	1,056,518,615
West Transmission	979,223,883	-	296,449,688		19,236,061	1,294,909,633
Total	**9,511,356,841**	**4,342,945**	**1,375,372,223**	**40,942,311**	**470,314,379**	**11,402,328,699**

Schedule Page: 200 Line No.: 21 Column: c

Company	Function	FERC Account	Total
East	General Plant	111010	7,662,720
	Intangible	111010	28,360,337
	Lease	111020	790,744
East Total			**36,813,801**
West Distribution	General Plant	111010	2,627,548
	Intangible	111010	17,052,308
West Distribution Total			**19,679,856**
West Transmission	Intangible	111010	1,298,450
West Transmission Total			**1,298,450**
Grand Total			**57,792,107**

Information on Formula Rates:
EAST:
Page 106 lines 10, 13 Depreciation related to station specific fixed assets.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance End of Year	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)	(f)	
			1
			2
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			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant	60,589,123	-70,468
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	60,589,123	-70,468
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)		
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	915,154	8,904,755
38	(341) Structures and Improvements	2,646,569	29,854,752
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators	27,169,284	75,565,804
42	(345) Accessory Electric Equipment	2,462,741	4,134,210
43	(346) Misc. Power Plant Equipment		
44	(347) Asset Retirement Costs for Other Production	1,439,574	2,295,692
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	34,633,322	120,755,213
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	34,633,322	120,755,213

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	65,746,009	91,959
49	(352) Structures and Improvements	142,671,619	19,753,093
50	(353) Station Equipment	1,594,805,263	79,087,705
51	(354) Towers and Fixtures	45,874,959	-7,582,217
52	(355) Poles and Fixtures	778,842,468	54,469,106
53	(356) Overhead Conductors and Devices	362,142,913	31,458,998
54	(357) Underground Conduit	138,678,248	13,943,811
55	(358) Underground Conductors and Devices	530,350,386	59,603,587
56	(359) Roads and Trails	52,682,480	5,814,880
57	(359.1) Asset Retirement Costs for Transmission Plant	652,725	400,461
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	3,712,447,070	257,041,383
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	18,026,676	272,712
61	(361) Structures and Improvements	102,861,308	24,001,148
62	(362) Station Equipment	921,556,152	19,049,188
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	444,505,518	16,106,209
65	(365) Overhead Conductors and Devices	867,323,888	33,850,915
66	(366) Underground Conduit	712,810,359	27,000,041
67	(367) Underground Conductors and Devices	1,595,320,180	74,910,815
68	(368) Line Transformers	663,755,904	8,671,545
69	(369) Services	391,609,531	28,096,839
70	(370) Meters	253,067,818	38,464,290
71	(371) Installations on Customer Premises	11,196,471	542,689
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	38,244,520	2,429,182
74	(374) Asset Retirement Costs for Distribution Plant	9,845,401	13,916,131
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	6,030,123,726	287,311,704
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	11,504,808	2,778,689
87	(390) Structures and Improvements	207,927,820	7,775,939
88	(391) Office Furniture and Equipment	32,932,111	-493,459
89	(392) Transportation Equipment	44,677,971	13,532,398
90	(393) Stores Equipment	2,839,552	633,522
91	(394) Tools, Shop and Garage Equipment	16,374,692	1,954,068
92	(395) Laboratory Equipment	985,987	
93	(396) Power Operated Equipment	230,773	-2,670
94	(397) Communication Equipment	94,457,486	11,111,190
95	(398) Miscellaneous Equipment	3,477,397	310,283
96	SUBTOTAL (Enter Total of lines 86 thru 95)	415,408,597	37,599,960
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	80,782	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	415,489,379	37,599,960
100	TOTAL (Accounts 101 and 106)	10,253,282,620	702,637,792
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	10,253,282,620	702,637,792

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
					3
			60,518,655		4
			60,518,655		5
					6
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					36
		198,701	10,018,610		37
			32,501,321		38
					39
					40
			102,735,088		41
			6,596,951		42
					43
			3,735,266		44
		198,701	155,587,236		45
		198,701	155,587,236		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
		2,767,962	68,605,930		48
336,788		-13,937,308	148,150,616		49
6,307,716		12,714,339	1,680,299,591		50
143,797			38,148,945		51
958,041			832,353,533		52
518,814			393,083,097		53
18,107			152,603,952		54
6,683,003		1,222,969	584,493,939		55
			58,497,360		56
			1,053,186		57
14,966,266		2,767,962	3,957,290,149		58
					59
10,215		-2,767,962	15,521,211		60
454,776			126,407,680		61
1,265,395		8,763	939,348,708		62
					63
2,423,621	-437		458,187,669		64
11,913,855	1,574	-117,392	889,145,130		65
601,093	-83	1,225	739,210,449		66
8,440,668		116,167	1,661,906,494		67
5,163,525	648,330	2,974,780	670,887,034		68
6,021,624	236,867		413,921,613		69
4,757,513			286,774,595		70
233,436		45,187	11,550,911		71
					72
761,544		-45,187	39,866,971		73
			23,761,532		74
42,047,265	886,251	215,581	6,276,489,997		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
		-198,701	14,084,796		86
7,247,841			208,455,918		87
275,676			32,162,976		88
1,863,579			56,346,790		89
32,096			3,440,978		90
192,683			18,136,077		91
317,213			668,774		92
			228,103		93
6,030,564			99,538,112		94
87,959			3,699,721		95
16,047,611		-198,701	436,762,245		96
					97
			80,782		98
16,047,611		-198,701	436,843,027		99
73,061,142	886,251	2,983,543	10,886,729,064		100
					101
					102
					103
73,061,142	886,251	2,983,543	10,886,729,064		104

Schedule Page: 204 Line No.: 5 Column: g

Intangible Plant broken out by Plant Account Between East, West Distribution, and West Transmission.

Plant Account	Company	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
303	East	40,711,178	(70,468)	-	-	-	40,640,710
	West Distribution	18,579,495	-	-	-	-	18,579,495
	West Transmission	1,298,450	-			-	1,298,450
303 Total		**$ 60,589,123**	**$ (70,468)**	**-**	-		**$ 60,518,655**

EAST:

Information on Formula Rates: Page 106 lines 10, 13:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 45 Column: g

Other Production Plant Broken out by Plant Account between East and West Distribution.

Plant Account	Company	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
340	East	-	6,924,323	-	-	-	6,924,323
	West Distribution	915,154	1,980,432	-	-	198,701	3,094,287
340 Total		**915,154**	**8,904,755**	**-**	-	**198,701**	**10,018,610**
341	East	-	13,172,435	-	-	-	13,172,435
	West Distribution	2,646,569	16,682,317	-	-	-	19,328,886
341 Total		**2,646,569**	**29,854,752**	**-**	**-**	**-**	**32,501,321**
344	East	-	31,650,288	-	-	-	31,650,288
	West Distribution	27,169,284	43,915,516	-	-	-	71,084,800
344 Total		**27,169,284**	**75,565,804**	**-**	**-**	**-**	**102,735,088**
345	East	-	1,809,811	-	-	-	1,809,811
	West Distribution	2,462,741	2,324,399	-	-	-	4,787,140
345 Total		**2,462,741**	**4,134,210**	**-**	**-**	**-**	**6,596,951**
346	East	-	-	-	-	-	-
	West Distribution	-	-	-	-	-	-
346 Total		**-**	**-**	**-**	**-**	**-**	**-**
347.1 ARO	East		1,029,702				1,029,702
	West Distribution	1,439,574	1,265,990				2,705,564
347.1 ARO Total		**1,439,574**	**2,295,692**	**-**	**-**	**-**	**3,735,266**
Subtotals	**East**	**-**	**54,586,559**	-	-	-	**54,586,559**
	West Distribution	**34,633,322**	**66,168,654**	-	-	**198,701**	**101,000,677**
Grand Total		**$ 34,633,322**	**$ 120,755,213**	**-**	**-**	**$ 198,701**	**$ 155,587,236**

Schedule Page: 204 Line No.: 49 Column: b

EAST:

Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 50 Column: b

EAST:

Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 58 Column: b

Localized transmission plant at the beginning of the year is : East Transmission is $ 28,961,117.
West Transmission is $ 7,199,998.

EAST:

Information on Formula Rates Page 106 line 23:
Investment base related to station specific fixed assets.

Information on Formula Rates Page 106 line 26:
Investment base as stipulated by contract.

WEST:

Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Schedule Page: 204 Line No.: 58 Column: g

Localized transmission plant at the end of the year is: East Transmission $ 28,961,117
West Transmission $ 7,199,998

Transmission activity broken out by Plant account between East Transmission and West Transmission.

Plant Account	Company	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
350	East Transmission	34,153,366	5	-	-	2,767,962	36,921,333
	West Transmission	31,592,643	91,954	-	-		31,684,597
350 Total		**65,746,009**	**91,959**	**-**		**2,767,962**	**68,605,930**
352	East Transmission	69,538,621	11,507,364	253,640	-	-	80,792,345
	West Transmission	73,132,998	8,245,729	83,148	-	(13,937,308)	67,358,271
352 Total		**142,671,619**	**19,753,093**	**336,788**	**-**	**(13,937,308)**	**148,150,616**
353	East Transmission	1,155,897,546	72,450,598	1,159,675	-	(1,222,968)	1,225,965,501
	West Transmission	438,907,717	6,637,107	5,148,041	-	13,937,307	454,334,090
353 Total		**1,594,805,263**	**79,087,705**	**6,307,716**	**-**	**12,714,339**	**1,680,299,591**
354	East Transmission	36,697,616	(180,885)	108,360	-	-	36,408,371
	West Transmission	9,177,343	(7,401,332)	35,437	-	-	1,740,574
354 Total		**45,874,959**	**(7,582,217)**	**143,797**	**-**	**-**	**38,148,945**
355	East Transmission	357,338,173	4,268,126	483,727	-	-	361,122,572
	West Transmission	421,504,295	50,200,980	474,314	-	-	471,230,961
355 Total		**778,842,468**	**54,469,106**	**958,041**	**-**	**-**	**832,353,533**
356	East Transmission	199,531,735	15,029,472	167,467	-	-	214,393,740
	West Transmission	162,611,178	16,429,526	351,347	-	-	178,689,357
356 Total		**362,142,913**	**31,458,998**	**518,814**	**-**	**-**	**393,083,097**
357	East Transmission	138,378,086	13,942,914	18,107	-	-	152,302,893
	West Transmission	300,162	897	-	-	-	301,059
357 Total		**138,678,248**	**13,943,811**	**18,107**	**-**	**-**	**152,603,952**
358	East Transmission	523,334,483	51,689,989	6,614,327	-	1,222,969	569,633,114
	West Transmission	7,015,903	7,913,598	68,676	-	-	14,860,825
358 Total		**530,350,386**	**59,603,587**	**6,683,003**	**-**	**1,222,969**	**584,493,939**
359	East Transmission	36,218,636	4,081,265	-	-	-	40,299,901
	West Transmission	16,463,844	1,733,615	-	-	-	18,197,459
359 Total		**52,682,480**	**5,814,880**	**-**	**-**	**-**	**58,497,360**
359.1 ARO	East Transmission	651,775	400,461	-	-	-	1,052,236

	West Transmission	950	-	-	-	-	950
359.1 ARO Total		**652,725**	**400,461**	**-**	**-**	**-**	**1,053,186**
Subtotals	**East Transmission**	**2,551,740,037**	**173,189,309**	**8,805,303**	**-**	**2,767,962**	**2,718,892,005**
	West Transmission	**1,160,707,033**	**83,852,074**	**6,160,963**	**-**		**1,238,398,144**
Grand Total		**$ 3,712,447,070**	**$ 257,041,383**	**$ 14,966,266**	**$ -**	**$2,767,962**	**$ 3,957,290,149**

EAST:
Information on Formula Rates Page 106 line 23:
Investment base related to station specific fixed assets.

Information on Formula Rates Page 106 line 26:
Investment base as stipulated by contract.

Information on Formula Rates Page 106.2 line 9:
Investment base as stipulated by contract.

WEST:
Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Information on Formula Rates Page 106.3 line 23:
Investment base as stipulated by contract.

Schedule Page: 204 Line No.: 61 Column: b
EAST:
Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 61 Column: g
EAST:
Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 62 Column: b
EAST:
Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 62 Column: g
EAST:
Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 66 Column: b
EAST:
Information on Formula Rates Page 106.2 line 5:

Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 66 Column: g

EAST:

Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 67 Column: b

EAST:

Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 67 Column: g

EAST:

Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 75 Column: b

EAST:

Information on Formula Rates Page 106 lines 10,13,16,19:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 75 Column: g

Distribution Balances and activity broken out by Plant account between East and West Distribution.

Plant Account	Company	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
360	East	16,605,927	272,712	10,215	-	(2,767,962)	14,100,462
	West Distribution	1,420,749	-	-	-	-	1,420,749
360 Total		**18,026,676**	**272,712**	**10,215**	**-**	**(2,767,962)**	**15,521,211**
361	East	96,178,605	23,802,700	444,935	-	-	119,536,370
	West Distribution	6,682,703	198,448	9,841	-	-	6,871,310
361 Total		**102,861,308**	**24,001,148**	**454,776**	**-**	**-**	**126,407,680**
362	East	832,654,356	12,075,091	1,003,923	-	-	843,725,524
	West Distribution	88,901,796	6,974,097	261,472	-	8,763	95,623,184
362 Total		**921,556,152**	**19,049,188**	**1,265,395**	**-**	**8,763**	**939,348,708**
363	East	-	-	-	-	-	-
	West Distribution			-	-	-	-
363 Total		**-**	**-**	**-**	**-**	**-**	**-**
364	East	365,520,677	11,125,383	1,048,389		-	375,597,671
	West Distribution	78,984,841	4,980,826	1,375,232	(437)	-	82,589,998
364 Total		**444,505,518**	**16,106,209**	**2,423,621**	**(437)**	**-**	**458,187,669**
365	East	705,861,390	20,044,169	8,112,438	1,609	-	717,794,730
	West Distribution	161,462,498	13,806,746	3,801,417	(35)	(117,392)	171,350,400
365 Total		**867,323,888**	**33,850,915**	**11,913,855**	**1,574**	**(117,392)**	**889,145,130**
366	East	641,248,429	21,908,521	54,836		-	663,102,114
	West Distribution	71,561,930	5,091,520	546,257	(83)	1,225	76,108,335
366 Total		**712,810,359**	**27,000,041**	**601,093**	**(83)**	**1,225**	**739,210,449**
367	East	1,434,672,795	65,228,514	6,810,569			1,493,090,740
	West Distribution	160,647,385	9,682,301	1,630,099	-	116,167	168,815,754
367 Total		**1,595,320,180**	**74,910,815**	**8,440,668**	**-**	**116,167**	**1,661,906,494**
368	East	579,825,514	5,957,106	3,573,924	648,330	18,239	582,875,265
	West Distribution	83,930,390	2,714,439	1,589,601	-	2,956,541	88,011,769
368 Total		**663,755,904**	**8,671,545**	**5,163,525**	**648,330**	**2,974,780**	**670,887,034**
369	East	316,280,445	24,463,620	5,460,022	-	-	335,284,043
	West Distribution	75,329,086	3,633,219	561,602	236,867	-	78,637,570
369 Total		**391,609,531**	**28,096,839**	**6,021,624**	**236,867**	**-**	**413,921,613**

370	East	221,928,793	35,409,458	3,517,416	-	-	253,820,835
	West Distribution	31,139,025	3,054,832	1,240,097	-	-	32,953,760
370 Total		**253,067,818**	**38,464,290**	**4,757,513**	**-**	**-**	**286,774,595**
371	East	-	-	-	-	-	-
	West Distribution	11,196,471	542,689	233,436	-	45,187	11,550,911
371 Total		**11,196,471**	**542,689**	**233,436**	**-**	**45,187**	**11,550,911**
373	East	20,068,277	1,511,438	182,229	-	-	21,397,486
	West Distribution	18,176,243	917,744	579,315		(45,187)	18,469,485
373 Total		**38,244,520**	**2,429,182**	**761,544**	**-**	**(45,187)**	**39,866,971**
374.1 ARO	East	9,268,703	7,393,471	-	-		16,662,174
	West Distribution	576,698	6,522,660	-	-	-	7,099,358
374.1 ARO Total		**9,845,401**	**13,916,131**	**-**	**-**	**-**	**23,761,532**
Subtotals	**East**	**5,240,113,911**	**229,192,183**	**30,218,896**	**649,939**	**(2,749,723)**	**5,436,987,414**
	West Distribution	**790,009,815**	**58,119,521**	**11,828,369**	**236,312**	**2,965,304**	**839,502,583**
Grand Total		**$ 6,030,123,726**	**$ 287,311,704**	**$ 42,047,265**	**$ 886,251**	**$ 215,581**	**$ 6,276,489,997**

EAST:
Information on Formula Rates Page 106 lines 10,13,16,19:
Investment base related to station specific fixed assets.

WEST:
Information on Formula Rates:
Page 106.3 line 15 and 19
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 99 Column: b

At the beginning of the year, there is $57,592 in General Plant Account 390, relating to rebranding.

EAST:
Information on Formula Rates Page 106 lines 10,13,16,19:
Investment base related to station specific fixed assets.

Schedule Page: 204 Line No.: 99 Column: g

EAST:
Information on Formula Rates Page 106 lines 10,13,16,19:
Investment base related to station specific fixed assets.

At the end of the year, there is $71,462 in General Plant Account 390, relating to rebranding.
East $ 57,592
West - $ 13,870

General Plant Broken out by Plant Account Between East, West Distribution, and West Transmission

Plant Account	Company	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
389	East	9,682,368	2,778,689	-	-	(198,701)	12,262,356
	West Distribution	1,821,608	-	-	-	-	1,821,608
	West Transmission	832	-	-	-	-	832
389 Total		**11,504,808**	**2,778,689**	**-**	**-**	**(198,701)**	**14,084,796**
390	East	183,490,229	5,601,873	7,247,841	-	-	181,844,261
	West Distribution	23,804,798	2,174,066	-	-	-	25,978,864
	West Transmission	632,793	-	-	-	-	632,793
390 Total		**207,927,820**	**7,775,939**	**7,247,841**	**-**	**-**	**208,455,918**
391	East	29,020,879	(747,325)	-	-	-	28,273,554
	West Distribution	3,608,169	253,866	275,676	-	-	3,586,359
	West Transmission	303,063	-	-	-	-	303,063

391 Total		**32,932,111**	**(493,459)**	**275,676**	**-**	**-**	**32,162,976**
392	East	25,006,758	11,570,539	46,282	-	-	36,531,015
	West Distribution	18,752,702	1,961,859	1,795,606	-	-	18,918,955
	West Transmission	918,511	-	21,691	-	-	896,820
392 Total		**44,677,971**	**13,532,398**	**1,863,579**	**-**	**-**	**56,346,790**
393	East	2,132,207	602,614	-	-	-	2,734,821
	West Distribution	707,345	30,908	32,096	-	-	706,157
	West Transmission	-	-	-	-	-	-
393 Total		**2,839,552**	**633,522**	**32,096**	**-**	**-**	**3,440,978**
394	East	9,220,849	1,090,155	103,673	-	-	10,207,331
	West Distribution	4,483,823	406,171	89,010	-	-	4,800,984
	West Transmission	2,670,020	457,742	-	-	-	3,127,762
394 Total		**16,374,692**	**1,954,068**	**192,683**	**-**	**-**	**18,136,077**
395	East	153,628	-	98,595	-	-	55,033
	West Distribution	487,931	-	218,618	-	-	269,313
	West Transmission	344,428	-	-	-	-	344,428
395 Total		**985,987**	**-**	**317,213**	**-**	**-**	**668,774**
396	East	2,670	(2,670)	-	-	-	-
	West Distribution	228,103	-	-	-	-	228,103
	West Transmission	-	-	-	-	-	-
396 Total		**230,773**	**(2,670)**	**-**	**-**	**-**	**228,103**
397	East	47,535,059	8,444,050	4,537,025	-	-	51,442,084
	West Distribution	18,396,102	577,807	1,459,882	-	-	17,514,027
	West Transmission	28,526,325	2,089,333	33,657	-	-	30,582,001
397 Total		**94,457,486**	**11,111,190**	**6,030,564**	**-**	**-**	**99,538,112**
398	East	3,138,919	310,283	65,131	-	-	3,384,071
	West Distribution	249,200	-	22,828	-	-	226,372
	West Transmission	89,278	-	-	-	-	89,278
398 Total		**3,477,397**	**310,283**	**87,959**	**-**	**-**	**3,699,721**
399.1 ARO	East						
	West Distribution	80,782					80,782
	West Transmission						
	399.1 ARO Total	**80,782**	-	-	-	-	**80,782**
Subtotals	**East**	**309,383,566**	**29,648,208**	**12,098,547**	**-**	**(198,701)**	**326,734,526**
	West Distribution	**72,620,563**	**5,404,677**	**3,893,716**	**-**	**-**	**74,131,524**
	West Transmission	**33,485,250**	**2,547,075**	**55,348**	**-**	**-**	**35,976,977**
Grand Total		**$ 415,489,379**	**$37,599,960**	**$16,047,611**	**$ -**	**$ (198,701)**	**$ 436,843,027**

Schedule Page: 204 Line No.: 100 Column: b

EAST:

Information on Formula Rates:

Page 106 line 30 — Amount stipulated per contract.

Page 106.2 lines 1,5 — Amount stipulated per contract.

Page 106 line 35 — Amount stipulated per contract and station specific fixed assets.

Page 106.1 lines 1,8,15,20,27,34 — Amount stipulated per contract and station specific fixed assets.

Page 106.2 line 35 Amount stipulated per contract.

Schedule Page: 204 Line No.: 100 Column: g

EAST:

Information on Formula Rates:

Page 106 line 30 Amount stipulated per contract.

Page 106.2 lines 1,5 Amount stipulated per contract.

Page 106 line 35 Amount stipulated per contract and station specific fixed assets.

Page 106.1 lines 1,8,15,20,27,34 Amount stipulated per contract and station specific fixed assets.

Page 106.2 line 35 Amount stipulated per contract.

Schedule Page: 204 Line No.: 104 Column: b

EAST:

Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Information on Formula Rates:

Page 106 line 30 Amount stipulated per contract.

Page 106.2 lines 1,5,9 Amount stipulated per contract.

Page 106 line 35 Amount stipulated per contract and station specific fixed assets.

Page 106.1 lines 1,8,15,20,27,34 Amount stipulated per contract and station specific fixed assets.

Page 106.2 line 29,35 Amount stipulated per contract and station specific

WEST:

Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Schedule Page: 204 Line No.: 104 Column: g

Total Plant in Service

Company	Beginning Balance	Additions	Retirements	Adjustments	Transfers	Ending Balance
East	8,141,948,692	486,545,791	51,122,746	649,939	(180,462)	8,577,841,214
West Distribution	915,843,195	129,692,852	15,722,085	236,312	3,164,005	1,033,214,279

West Transmission	1,195,490,733	86,399,149	6,216,311	-	-	1,275,673,571
Total	**10,253,282,620**	**702,637,792**	**73,061,142**	**886,251**	**2,983,543**	**10,886,729,064**

EAST:
Information on Formula Rates Page 106.2 line 5:
Investment base related to station specific fixed assets.

Information on Formula Rates:

Page 106 line 30	Amount stipulated per contract.
Page 106.2 lines 1,5,9	Amount stipulated per contract.
Page 106 line 35	Amount stipulated per contract and station specific fixed assets.
Page 106.1 lines 1,8,15,20,27,34	Amount stipulated per contract and station specific fixed assets.
Page 106.2 line 29,35	Amount stipulated per contract and station specific

WEST:
Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II
Page 106.3 line 9

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2	Not Applicable				
3					
4					
5					
6					
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46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Distribution:			
3	Boston - Taber and Harrison Ave	1987	2019	10,226
4	Norfolk - Dean Street	1987-1991	2020	8,475
5	Natick - Mill Street	1987	2019	60,794
6	Yarmouth - Dennis/Yarmouth Station	2008	2019	489,536
7	Parcel F-8-B South Boston - Substation	2009	2019	591,505
8	Freemont Street - Distribution	2015	2022	2,895,553
9	Fulkerson Street - Cambridge - Distribution	2017	2022	7,883,464
10	Dist. Line - Boston	2017	2019	568,709
11	70 Fremont Street - Distribution	2018	2019	527,441
12	Transmission:			
13	Yarmouth - Dennis/Yarmouth Station	2008	2023	492,805
14	Falmouth - Off Currier Road	2015	2021	645,893
15	Parcel F-8 B South Boston - Substation	2009	2019	197,169
16	Freemont Street - Transmission	2015	2022	1,976,737
17	Boston - Hyde Park Substation	2014	2020	11,535,494
18	Future Charlestown S/S - 492 Rutherford Avenue	2016	2024	7,074,168
19	Fulkerson Street - Cambridge - Transmission	2017	2022	5,255,997
20	70 Fremont Street - Transmission	2018	2019	351,682
21	Other Property:			
22	Minor Items (2): Transmission Rights of Way			209,302
23	and Pembroke Street			
24				
25				
26	Land and Land Rights-WEST			
27	53 Russell Street, Hadley, MA	2018	2021	167,361
28				
29				
30				
31				
32				
33				
34				
35	Functionalized: EAST			
36	Distribution 13,035,703			
37	Transmission 27,739,247			
38	Total 40,774,950			
39				
40	Functionalized: WEST			
41	Distribution 167,361			
42	Transmission 0			
43	Total 167,361			
44				
45				
46				
47	Total			40,942,311

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	NSTAR Electric East	
2		
3	East Distribution Plant	
4		
5	Acts of Public Authority - Mass Ave	1,914,609
6	Mass Property Overheads	1,641,867
7	Design Engineering Distribution Substation	1,457,988
8	Carver Station 71 Transformer Replacements	1,550,201
9	Line Convert 344-04 To 13.8KV	1,214,250
10	Communication on Fiber Wire	1,049,406
11	Distribution - Northpoint Parcel North	2,501,224
12	Pole Program	2,414,144
13	Framington Like for Like Replacement	2,390,132
14	Line Upgrade 3-25-25	3,122,936
15	Logan Line Upgrade	2,131,220
16	Mass Ave Like for Like Replacement	9,350,130
17	Minor Cap Improvement & Failure Station	7,841,790
18	Minor Capital Improvements Mass Ave	3,636,481
19	Minor Distribution System Improvement Waltham	2,581,659
20	Distribution System Minor Improvements	1,092,760
21	Minor Station Improvements & Failures	1,639,909
22	Minor System Improvement Somerville	1,058,437
23	Comm Ave Bridge Phase 2 &3	1,846,780
24	North Customer Mass Ave	2,556,461
25	Electric Vehicle Chargers	1,219,282
26	Line Improvements PPC 320-H1	1,862,131
27	Pulte Homes Leg Farms	3,650,396
28	Service to New Customer Station 137	1,422,965
29	SFM Replacements	2,110,827
30	Underground Cable Like for Like Replacement	4,745,322
31	Spare Transformer 90 MVA	1,708,045
32	Station 126 3rd Auto at Hopkinton-Distribution Lane	1,948,395
33	Station 131 East Boston - Distribution	7,938,047
34	Station 315 Electric Ave	14,455,840
35	Station 329 Replace Transformer	4,450,757
36	Station 715 Valley Replace Transformers	5,576,806
37	Station 99 Seafood Way	17,754,516
38	Post Storm Capital Work	14,235,010
39	Tremont Station 713 Transformer Replace	1,226,317
40	URD Cable Cure Injection Upgrades	5,847,172
41	URD Wood Duck Way	1,264,884
42	Waltham Like for Like Replacement	1,198,661
43	TOTAL	470,314,379

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Minor Projects Under $1,000,000	37,127,151
2	East Distribution Plant Subtotal $182,734,908	
3		
4	East General Plant	
5		
6	2018 FAC NE LOB Bldgs	2,823,595
7	Mass East Vehicle Purchases Distribution	2,212,547
8	Small Tools Mass East	1,013,007
9	Minor Projects Under $1,000,000	3,208,912
10	East General Plant Subtotal $9,258,061	
11		
12	East Intangible Plant	
13		
14	Minor Projects Under $1,000,000	139,401
15	East Intangible Plant Subtotal $139,401	
16		
17	East Other Production	
18		
19	Mass Solar Project	23,979,011
20	East Other Production Plant Subtotal $23,979,011	
21		
22	East Transmission Plant	
23		
24	Andrew Square Dewar St	1,129,844
25	Preliminary Engineering Transmission Station	2,074,921
26	Chelsea Substation Project	2,553,183
27	Critical Infrastructure V14 IDS	1,395,592
28	Digital Fault Recorders Replace	1,492,864
29	EMA Battery Monitoring	1,693,971
30	Extend 115 KV Line 114	1,188,172
31	Fulkerson Station 8025 - Transmission Station	1,647,664
32	Line 115 Mid Cape	3,073,442
33	Line 115kV Underground Woburn	38,492,550
34	Line 146 to 502 Walpole to Holbrook	17,814,761
35	Line 345kV Woburn Station 211 to Wakefield	17,106,043
36	Mystic to Chelsea - Transmission Line GB	13,100,527
37	New Line 115kV Sudbury to Hudson GB	12,077,119
38	Rebuild Bourne Substation SRIA	1,440,292
39	Replace Brown Glass Ins Station 446	1,661,618
40	Station 117 Sharon Switching Station GB	12,960,743
41	Station 446 Control House & Line cutovers	2,185,841
42	Station 131 East Boston - Transmission Line	1,512,005
43	TOTAL	470,314,379

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Station 131 East Boston - Transmission Station	4,714,914
2	Station 2 Hawkins GIS & High Side Breakers	1,042,460
3	Station 211 Replace Woburn Transformer	14,853,045
4	Station 250 Install 2nd Transformer Mystic GB	14,714,720
5	Station 250 Upgrade Control House	3,654,828
6	Station 329 Control House & Line cutovers	1,043,938
7	Station 385 Control House & Line cutovers	1,820,779
8	Station 385 Shunt Reactor	4,890,567
9	Station 514 Replace 115KV Breakers	7,024,809
10	Station 65 Medway Substation Project	1,488,784
11	Transmission Line North	2,617,674
12	Transmission Station Improvements North	4,807,063
13	West Roxbury to Needham Reliab GB	4,871,021
14	Minor Projects Under $1,000,000	9,684,207
15	East Transmission Plant Subtotal $211,829,961	
16		
17	NSTAR Electric East Total $427,941,342	
18		
19		
20	NSTAR Electric West Distribution	
21		
22	West Distribution Plant	
23		
24	East Springfield Transformer Replacement	1,700,783
25	Montague Transformer Upgrade	2,612,748
26	Orchard Substation Transformer Addition	1,334,323
27	Replace Gunn Transformer	2,427,865
28	Western Mass Grid Mod Relay Replacement Agawam	1,070,684
29	Western Mass Grid Mod Feeder Relay	1,447,376
30	Minor Projects Under $1,000,000	8,831,015
31	West Distribution Plant Subtotal $19,424,794	
32		
33	West General Plant	
34		
35	2018 West Distribution Buildings and General Plant	1,193,220
36	Minor Projects Under $1,000,000	2,471,399
37	West General Plant Subtotal $3,664,619	
38		
39	West Other Production Plant	
40		
41	Minor Projects Under $1,000,000	47,563
42	West Other Production Plant Subtotal $47,563	
43	TOTAL	470,314,379

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1		
2	West Distribution Total $23,136,976	
3		
4		
5	West Transmission	
6		
7	West Transmission General Plant	
8		
9	Minor Projects Under $1,000,000	88,335
10	West Transmission General Plant Subtotal $88,335	
11		
12	West Transmission Transmission Plant	
13		
14	Transmission Line Projects - 2018	2,980,939
15	Transmission Line 393 ACR	1,457,427
16	Ludlow 115KV Equipment Replace	1,451,269
17	PGA-2 1512 Line Loop	1,221,080
18	PGA-2 Atwater-New Switching Station	1,928,617
19	PGA-2 Buck Pond Substation Modifications	1,733,209
20	PGA-2 New 115kV 1293 Line	1,770,082
21	Minor Projects Under $1,000,000	6,605,103
22	West Transmission Transmission Plant Subtotal $19,147,726	
23		
24	West Transmission Total $ 19,236,061	
25		
26	NSTAR Electric West total $42,373,037	
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38		
39		
40		
41		
42		
43	TOTAL	470,314,379

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	2,750,485,246	2,750,485,246		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	271,328,755	271,328,755		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	4,551,027	4,551,027		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	275,879,782	275,879,782		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	73,051,031	73,051,031		
13	Cost of Removal	25,568,806	25,568,806		
14	Salvage (Credit)	777,128	777,128		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	97,842,709	97,842,709		
16	Other Debit or Cr. Items (Describe, details in footnote):	-18,382,595	-18,382,595		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,910,139,724	2,910,139,724		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production				
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	10,140,974	10,140,974		
25	Transmission	712,168,339	712,168,339		
26	Distribution	2,069,226,068	2,069,226,068		
27	Regional Transmission and Market Operation				
28	General	118,604,343	118,604,343		
29	TOTAL (Enter Total of lines 20 thru 28)	2,910,139,724	2,910,139,724		

Schedule Page: 219 Line No.: 12 Column: c

Book Cost of Plant Retired:

Retirements from reserves	$73,051,031
Miscellaneous reserve retirements	10,111
Total retirements (ties to page 207)	$73,061,142

Schedule Page: 219 Line No.: 16 Column: c

Other debit or (credit) items

Sundry billing	$ 102,645
Journal entries	(153,318)
Transfers and adjustments	1,989,195
ARO activity	937,437
Total removal work in progress	(21,258,555)
Total other debits or credit items	$ (18,382,595)

Schedule Page: 219 Line No.: 19 Column: c

Information on Formula Rates:

Page 106.2 line 1 Depreciation amount stipulated by contract.

Schedule Page: 219 Line No.: 24 Column: c

Company	Function	Balance
East	Other	421,802
West Distribution	Other	9,719,172
Total		**$ 10,140,974**

Schedule Page: 219 Line No.: 25 Column: c

Company	Function	Balance
East	Transmission	617,843,746
West Transmission	Transmission	94,324,594
Total		**$ 712,168,339**

EAST:

Information on Formula Rates:

Page 106.2 line 5 Depreciation amount stipulated by contract.

WEST:

Information on Formula Rates:

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II. Reference Page 106.3 line 9.

Schedule Page: 219 Line No.: 26 Column: c

Company	Function	Balance
East	Distribution	1,834,262,908
West Distribution	Distribution	234,963,160
Total		**$ 2,069,226,068**

EAST:

Information on Formula Rates:

Page 106 lines 10,13 Depreciation related to station specific fixed assets.

Page 106.2 line 5 Depreciation related to station specific fixed assets.

Page 106.2 line 1 Depreciation amount stipulated by contract.

Schedule Page: 219 Line No.: 28 Column: c

Company	Function	Balance
East	General	85,222,756
West Distribution	General	24,195,841
West Transmission	General	9,185,746
Total		**$ 118,604,343**

EAST:

Information on Formula Rates:

Page 106 lines 10,13 Depreciation related to station specific fixed assets.

Page 106.2 line 1 Depreciation amount stipulated by contract.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Connecticut Yankee Atomic Power Company			
2	Common Stock			469,654
3	Equity and Dividends			-33,870
4	Subtotal			435,784
5				
6	Maine Yankee Atomic Power Company			
7	Common Stock			135,307
8	Equity and Dividends			26,361
9	Subtotal			161,668
10	Yankee Atomic Electric Company (Massachusetts)			
11	Common Stock			161,070
12	Equity and Dividends			156,798
13	Subtotal			317,868
14				
15	Harbor Electric Energy Company			
16	Common Stock			1,000
17	Capital Contribution			4,400,000
18	Undistributed subsidiary earnings			-5,430,671
19	Subtotal			-1,029,671
20				
21	New England Hydro-Transmission Electric Company			
22	Common Stock			68,719
23	Capital Contribution			4,520,245
24	Undistributed subsidiary earnings			1,471,168
25	Subtotal			6,060,132
26				
27	New England Hydro-Transmission Corporation			
28	Common Stock			1,446
29	Capital Contribution			521,105
30	Undistributed subsidiary earnings			323,173
31	Subtotal			845,724
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	6,791,505

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
	-1	469,655		2
19,814		-14,056		3
19,814	-1	455,599		4
				5
				6
		135,307		7
7,331		33,692		8
7,331		168,999		9
				10
		161,070		11
-4,742		152,056		12
-4,742		313,126		13
				14
				15
		1,000		16
	13,500,000	17,900,000		17
-4,963,149		-10,393,820		18
-4,963,149	13,500,000	7,507,180		19
				20
				21
		68,719		22
		4,520,245		23
642,557		2,113,725		24
642,557		6,702,689		25
				26
				27
		1,446		28
		521,105		29
31,336		354,509		30
31,336		877,060		31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
-4,266,853	13,499,999	16,024,653		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)			
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)	10,762,392	15,734,279	Electric
9	Distribution Plant (Estimated)	38,769,138	45,959,392	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	49,531,530	61,693,671	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	391,487	45,571	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	49,923,017	61,739,242	

FOOTNOTE DATA

Schedule Page: 227 Line No.: 8 Column: b

Transmission Inventory:
East $8,146,367
West 2,616,025
Total $10,762,392

Calculated per company records as stipulated per contract.
Reference Page 106 line 1.

Schedule Page: 227 Line No.: 8 Column: c

EAST-Calculated per company records as stipulated per contract.
Reference Page 106 line 1.

Transmission Inventory:
East $13,131,552
West 2,602,727
Total $15,734,279

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		2019	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2020		2021		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
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								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		2019	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year		50,391,921		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10	Massachusetts Renewable		65,594,115		
11	Energy Certificate				
12					
13					
14					
15	Total		65,594,115		
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23	Massachusetts Renewable		50,391,921		
24	Energy Certificate				
25					
26					
27					
28	Total		50,391,921		
29	Balance-End of Year		65,594,115		
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2020		2021		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
							50,391,921	1
								2
								3
								4
								5
								6
								7
								8
								9
							65,594,115	10
								11
								12
								13
								14
							65,594,115	15
								16
								17
								18
								19
								20
								21
								22
							50,391,921	23
								24
								25
								26
								27
							50,391,921	28
							65,594,115	29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

FOOTNOTE DATA

Schedule Page: 229 Line No.: 29 Column: c

Represents the value of Renewable Energy Certificates (RECs) that NSTAR Electric Company uses to meet the Commonwealth of Massachusetts' Renewable Portfolio Standards requirements. These RECs are recorded in Account 158.3.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Not Applicable					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	Not Applicable					
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	Atlantic Link	2,433	186	2,433	186
3	Bay State Wind	3,858	186	3,602	186
4	Brayton Point Wind	124	186		
5	Cabot Power	27,099	186	9,229	186
6	Canal	3,221	186		
7	Clean Energy Connect	2,042	186	3,233	186
8	Cross Rd	618	186	124	186
9	Falmouth Energy Storage	757	186	757	186
10	MacDill Solar	11,231	186	10,294	186
11	Maine Green Line	747	186	747	186
12	Maine Power Express	121,990	186	123,042	186
13	Northeast Renewable Link	8,499	186	8,499	186
14	Revolutionary Wind	263	186		
15	UMASS	9,434	186		
16	Vineyard Wind	1,141	186	3,087	186
17	Vineyard Wind 2	371	186	124	186
18					
19					
20					
21	**Generation Studies**				
22					
23	None				
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Fuel litigation costs	200,527	4,773			205,300
2						
3	Connecticut Yankee Shutdown Costs:					
4	On 12/4/96, the Board decided to cease					
5	operations at the nuclear power plant. This					
6	is NSTAR Electric's share of estimated costs					
7	for plant closure and fuel storage obligations.	1,037,020	15,832	253/555	43,816	1,009,036
8						
9	Massachusetts Yankee Shutdown Costs:					
10	On 2/26/92, the Board decided to cease					
11	operations at the nuclear power plant. This					
12	is NSTAR Electric's share of estimated costs					
13	for plant closure and fuel storage obligations.	16,873	17,843	253/555	9,340	25,376
14						
15	Maine Yankee Shutdown Costs:					
16	On 8/6/97, the Board decided to cease					
17	operations at the nuclear power plant. This					
18	is NSTAR Electric's share of estimated costs					
19	for plant closure and fuel storage obligations.	411,472	2,865	253/555	21,728	392,609
20						
21	Income tax regulatory liability ASC 740					
22	(elements amortized over various periods)	117,390,939	6,840,940	283/407.3	9,150,129	115,081,750
23						
24	Asset Retirement Obligation ASC 410	39,005,483	3,150,381			42,155,864
25						
26	NSTAR Goodwill - 40 year amortization	313,577,627		407.3	14,472,829	299,104,798
27	D.P.U. 99-19					
28						
29	Prepaid Pension	401,805,851	57,422,414			459,228,265
30						
31	Pension and PBOP ASC 715	158,637,879	106,025	228.3/926	74,534,899	84,209,005
32						
33	Basic Service Reconciliation:					
34	D.P.U. 06-40, 97-120					
35	The Company defers the cost to					
36	provide basic service to customers compared					
37	to amounts billed to customers, plus carrying					
38	charge.	28,241,837	4,415,172	555	32,657,009	
39						
40	Residential Assistance Adjustment Clause:					
41	This mechanism allows for the recovery of					
42	costs related to low income Residential					
43	Assistance D.P.U. 12-126, 01-106B, 04-106	20,700,578	17,692,300	904/407.4	21,964,965	16,427,913
44	TOTAL	1,504,849,772	509,187,395		585,701,808	1,428,335,359

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1						
2	AFUDC (D.P.U. method amortized over 42 years)	2,410,998		407.3	270,900	2,140,098
3						
4	NSTAR Green implementation costs	26,059		407.4	26,059	
5	D.P.U. 07-64-A					
6						
7	Energy contract derivative	1,232,421		244	1,109,315	123,106
8						
9	Net metering D.P.U. 12-116, 09-74	16,949,221	187,902,005	Footnote	204,851,226	
10						
11	Attorney General consultant expenses	691,751	219,341	407.3	676,732	234,360
12	D.P.U. 11-90, 10-70					
13						
14	Deferred storm restoration costs	127,037,412	14,278,722	407.3	21,524,757	119,791,377
15	D.P.U. 96-23, 05-85					
16						
17	Recoverable storm costs 2011 D.P.U. 13-52	8,192,148	196,162	407.3	8,388,310	
18						
19	Deferred storm restoration costs					
20	D.P.U. 06-55	11,358,509	201,875	407.3	6,323,279	5,237,105
21						
22	Deferred storm restoration costs					
23	D.P.U. 17-05		94,835,431			94,835,431
24						
25	Long term renewable contract adjustment					
26	D.P.U. 11-05, 11-06, 11-07					
27	This mechanism allows for the recovery of					
28	costs associated with Long-Term Renewable					
29	Contracts that are in place to satisfy the					
30	requirements of the Green Communities					
31	Act	37,890,928	1,257,394	555	24,381,210	14,767,112
32						
33	Energy Efficiency Reconciliation	151,722,648	79,326,854	Footnote	142,702,915	88,346,587
34	D.P.U. 13-121, 89-260					
35						
36	Uncollectibles Associated with Basic Service	1,847,399	7,035,783	Footnote	8,883,182	
37	D.P.U. 03-88A, 03-88A-F					
38						
39	Resiliency Tree Work D.P.U. 17-05	2,983,635	22,407,585			25,391,220
40						
41	Merger Costs D.P.U. 17-05	30,523,730		407.3	2,500,755	28,022,975
42	(10 year amortization)					
43						
44	TOTAL	1,504,849,772	509,187,395		585,701,808	1,428,335,359

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Customer Hardship D.P.U. 17-05	23,500,334		904	4,324,728	19,175,606
2	(5 year amortization)					
3						
4	Rate Case Costs D.P.U. 17-05	4,697,429		407.3	861,195	3,836,234
5	(5 year amortization)					
6						
7	CPSL Costs D.P.U. 05-85	29,080	18,677	182.3	47,757	
8						
9	Revenue Decoupling D.P.U. 17-05	2,087,597	3,502,563	407.4	5,590,160	
10						
11	Federal Tax Rate Reduction	384,613		190	384,613	
12						
13	Other Benefit Deferrals (ASC 715)	257,774	727,016			984,790
14						
15	Solar Program D.P.U. 09-05, 16-105		6,404,967			6,404,967
16						
17	Grid Modernization Plan D.P.U. 15-122		197,619			197,619
18						
19	Smart Solar D.P.U. 17-140		1,006,856			1,006,856
20						
21						
22						
23						
24						
25						
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36						
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38						
39						
40						
41						
42						
43						
44	TOTAL	1,504,849,772	509,187,395		585,701,808	1,428,335,359

FOOTNOTE DATA

Schedule Page: 232 Line No.: 22 Column: f

NSTAR Electric East Distribution	$ 82,644,846
NSTAR Electric West Distribution	32,436,904
Total	$115,081,750

Schedule Page: 232 Line No.: 29 Column: f

NSTAR Electric East Distribution	$459,228,265

Schedule Page: 232 Line No.: 31 Column: f

NSTAR Electric West Distribution	$85,796,408
NSTAR Electric East Distribution	(1,587,403)
Total	$84,2009,005

Schedule Page: 232.1 Line No.: 9 Column: d

Account:	Amount:
456	$188,724,348
555	14,985,094
407.4	1,035,634
431	106,150
Total	$204,851,226

Schedule Page: 232.1 Line No.: 33 Column: d

Account:	Amount:
447	$ 70,016,520
908	52,675,882
242	13,260,320
142	6,750,193
Total	$142,702,915

Schedule Page: 232.1 Line No.: 36 Column: d

Account:	Amount:
904	$7,208,685
186	1,669,359
431	5,138
Total	$8,883,182

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Deferred basic service bad debt	7,504,709	14,158,494	144/904	13,802,778	7,860,425
2	costs					
3						
4	Reimbursable substation costs	6,565,711		565	471,788	6,093,923
5						
6	Unamortized revolver fees	2,147,548	1,090,730	428/431	1,244,495	1,993,783
7						
8	Deferred insurance costs	18,583,149	3,640,026			22,223,175
9						
10	Allowance for hardship accounts	21,925,521	9,801,788	144/904	4,279,003	27,448,306
11						
12	Real estate transactions	541,869	18,834			560,703
13						
14	Cape Wind transmission study	-168,800	168,800			
15						
16	EESCO Long Term Receivable	5,452,453				5,452,453
17						
18	Mutual aid storm work	1,564,798		588	1,564,798	
19						
20	Massachusetts solar	551,072	455,784	182.3	1,006,856	
21						
22	Deferred property tax Increases	11,328,627				11,328,627
23						
24	Facilities impairment deferral	474,767				474,767
25						
26	Farm discount deferral		549,941			549,941
27						
28	Environmental reserve		4,367,406			4,367,406
29						
30	Minor items	337,967	1,725,233	143/142	394,538	1,668,662
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	76,809,391				90,022,171

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2		398,218,961	462,181,372
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	398,218,961	462,181,372
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	398,218,961	462,181,372

Notes

Schedule Page: 234 Line No.: 2 Column: b

EAST	WEST	TOTAL
305,411,665	92,807,296	398,218,961

WEST:

At the beginning of the year, the total balance of Accumulated Deferred Income Taxes in Account 190 includes a transmission related component of $43,444,604. In addition, Account 254 includes a transmission related component of ($1,058,337) transferred from this account as a result of the Federal Income Tax Act.

At the beginning of the year, the total balance of Accumulated Deferred Income Taxes in Account 190 (Reserve for Disputed Transactions) includes a transmission related component of $0.

Information on Formula Rates:

Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.
Reference Page 106, Line 1.

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.
Reference Page 106, Line 1.

Schedule Page: 234 Line No.: 2 Column: c

EAST	WEST	TOTAL
359,927,916	102,253,456	462,181,372

EAST:

	Amount	Business Unit
Post employment benefits accrued	$23,812,128	All (Labor)
Workers Compensation	2,995,474	All (Labor)
Workers Compensation gross up payable	4,801,981	All (Labor)
Performance Reward Program	1,544,052	All (Labor)
Self insurance reserves	1,828,932	All (Plant)
Allowance for uncollectible accounts	13,134,705	Distribution
Hazardous waste reserves	3,737,290	All (Plant)
Pension expense	35,681,234	All (Labor)
Pension adjustment mechanism	15,697,526	Retail Adjuster Clause
Deferred default service	1,234,425	Retail Adjuster Clause
Deferred Net Metering Costs	6,183,796	Distribution
Deferred Energy Efficiency	6,231,740	Retail Adjuster Clause
Storm Contingency Fund	1,408,432	Distribution
Deferred transmission revenues	24,310,434	Retail Adjuster Clause
ASC 740 deferred income taxes (FAS109)	212,753,695	All (Plant)
Other items	4,572,072	All (Plant)
Total	$359,927,916	

Information on Formula Rates page 106.2 line 1,35:
Amount as stipulated per contract.

WEST:

	Beginning Balance	Activity	Ending Balance
Account 190 ASC 740 Gross-Up (FAS 109)	74,170,428	2,003,515	76,173,943
Account 190 ASC 740 ITC (FAS 109)	2,117,016	3,498,239	5,615,255
Account 190 Comprehensive Income	860,075	(192,672)	667,403
Account 190 Asset Retirement Obligations	1,633,508	2,285,139	3,918,647
Bad Debts	3,867,260	797,023	4,664,283
Employee Benefits	8,102,124	(295,697)	7,806,427
Regulatory Deferrals	1,619,099	2,390,483	4,009,582
Other	437,786	(1,039,870)	(602,084)
Sub-total ARO's	15,659,777	4,137,078	19,796,855
TOTAL 190	92,807,296	9,446,160	102,253,456

At the beginning of the year, the total balance of Accumulated Deferred Income Taxes in Account 190 includes a transmission related component of $43,444,604.

At the beginning of the year, the total balance of Accumulated Deferred Income Taxes in Account 190 (Reserve for Disputed Transactions) includes a transmission related component of $0.

At the end of the year, the total balance of Accumulated Deferred Income Taxes in Account 190 includes a transmission related component of $41,969,598.

At the end of the year, the total balance of Accumulated Deferred Income Taxes in Account 190480 (Reserve for Disputed Transactions) includes a transmission related component of $0.

FOOTNOTE DATA

Information on Formula Rates:
Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.
Reference Page 106, Line 1.

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.
Reference Page 106, Line 1.

Schedule Page: 234 Line No.: 18 Column: b

Information on Formula Rates: See line 1 for additional information:
Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II. Reference Page 106.3, Line 9.

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.
Reference Page 106.3, Line 9.

Schedule Page: 234 Line No.: 18 Column: c

Information on Formula Rates: See line 1 for additional information:
Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II. Reference Page 106.3, Line 9.

Calculated per company records and in accordance with Schedule 21-ES, Attachment I under ISO New England Inc. Transmission, Markets and Services Tariff, Section II.
Reference Page 106.3, Line 9.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201:			
2	Common Stock	200	1.00	
3				
4				
5				
6				
7	Total Common	200	1.00	
8				
9				
10	Account 204:			
11	Cumulative preferred NSTAR Electric East:			
12	4.25% series	180,000	100.00	103.63
13	4.78% series	250,000	100.00	102.80
14				
15				
16				
17	Authorized and unissued	2,460,000		
18				
19	Total Preferred	2,890,000		
20				
21				
22				
23				
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42				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
200	200					2
						3
						4
						5
						6
200	200					7
						8
						9
						10
						11
180,000	18,000,000					12
250,000	25,000,000					13
						14
						15
						16
						17
						18
430,000	43,000,000					19
						20
						21
						22
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						27
						28
						29
						30
						31
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						42

FOOTNOTE DATA

Schedule Page: 250 Line No.: 19 Column: f

Total is 100% Eastern Massachusetts.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Donations Received from Stockholders (Account 208)	
2	None	
3		
4		
5	Reduction in Par or Stated Value of Capital Stock (Account 209)	
6	None	
7		
8		
9	Gain on Resale or Cancellation of Reacquired Capital Stock	
10	(Account 210)	
11	None	
12		
13		
14	Miscellaneous Paid-In Capital (Account 211)	
15		
16		
17	Beginning balance	2,673,237,858
18	Capital contribution from Parent Company	130,000,000
19	WEST-Common stock balance reclassifed on 2018 merger	10,866,225
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	2,814,104,083

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Not Applicable	
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 224 (NSTAR Electric East)		
2	2006 $200M 5.75% Debentures	200,000,000	2,180,549
3			17,719,179
4			2,114,000 D
5	2010 $300M 5.50% Debentures	300,000,000	3,123,342
6			4,806,000 D
7	2012 $400M 2.375% Debentures	400,000,000	3,178,574
8			1,096,000 D
9	2014 $300M 4.4% Debentures	300,000,000	3,064,448
10			2,073,000 D
11	2016 $250M 2.7% Debentures	250,000,000	2,140,898
12			870,000 D
13	2015 $250M 3.25% Debentures	250,000,000	2,129,952
14			1,202,500 D
15	2017 $700M 3.20% Debentures	700,000,000	6,340,099
16			266,000 D
17			-4,105,500 P
18	Senior Notes (Nstar Electric West)		
19	2004 Series B, 5.90% Fixed Rate	50,000,000	546,179
20			173,500 D
21	2007 Series D, 6.70% Fixed Rate	40,000,000	501,464
22			189,200 D
23	2010 Series E, 5.10% Fixed Rate	95,000,000	991,276
24			336,300 P
25	2011 Series F, 3.50% Fixed Rate	250,000,000	2,247,325
26			908,000 D
27			-9,571,500 P
28	2013 Series G, 3.88% Fixed Rate	80,000,000	450,757
29			
30	2016 Series H, 2.75% Fixed Rate	50,000,000	308,911
31	Column (c): expenses listed first, followed by call premiums,		
32	then discount (D)/premium (P) for each obligation		
33	TOTAL	2,965,000,000	45,280,453

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Additional Footnotes.		
2			
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25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	2,965,000,000	45,280,453

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
03/16/2006	03/15/2036	03/2006	03/2036	200,000,000	11,500,000	2
						3
						4
03/16/2010	03/15/2040	03/2010	03/2040	300,000,000	16,500,000	5
						6
10/15/2012	10/15/2022	10/2012	10/2022	400,000,000	9,500,000	7
						8
03/07/2014	03/01/2044	03/2014	03/2044	300,000,000	13,200,000	9
						10
05/26/2016	06/01/2026	05/2016	06/2026	250,000,000	6,750,000	11
						12
11/18/2015	11/15/2025	11/2015	11/2025	250,000,000	8,125,000	13
						14
05/15/2017	05/15/2027	05/2017	05/2027	700,000,000	22,400,000	15
						16
						17
						18
09/23/2004	09/15/2034	10/2004	09/2034	50,000,000	2,950,000	19
						20
08/17/2007	08/15/2037	08/2007	08/2037	40,000,000	2,680,000	21
						22
03/08/2010	03/01/2020	03/2010	02/2020	95,000,000	4,845,000	23
						24
09/16/2011	09/15/2021	09/2011	08/2021	250,000,000	8,750,000	25
						26
						27
11/15/2013	11/15/2023	11/2013	11/2023	80,000,000	3,104,000	28
						29
06/23/2016	06/15/2026	06/2016	06/2026	50,000,000	1,375,000	30
						31
						32
				2,965,000,000	111,679,000	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
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						30
						31
						32
				2,965,000,000	111,679,000	33

FOOTNOTE DATA

Schedule Page: 256.1 Line No.: 1 Column: a

Excluded from the total interest for the year is $3,569 for interest related to other comprehensive income.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	383,090,152
2		
3		
4	Taxable Income Not Reported on Books	
5	Contributions in aid of construction - East	24,096,521
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See footnote	651,827,353
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See footnote	40,759,325
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See footnote	547,183,176
21		
22	Taxable Income - line 1 + line 5 +line 10 - line 15 -line 20	471,071,525
23	State Income taxes - East	-29,784,460
24	State Tax - Prior Year Adjustment -East	773,900
25		
26		
27	Federal Tax Net Income	442,060,965
28	Show Computation of Tax:	
29		
30	Estimated federal tax payable @21%	92,832,803
31		
32		
33		
34		
35		
36		
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41		
42		
43		
44		

Schedule Page: 261 Line No.: 1 Column: b

	EAST	WEST	TOTAL
Net Income	315,658,727	67,431,425	383,090,152

Schedule Page: 261 Line No.: 10 Column: b

	EAST	WEST	TOTAL
Deductions on books not on the return	609,169,015	42,658,338	651,827,353

EAST:

Deductions on books not on the return	
Compensation expense	5,651,729
Bond redemption amortization	606,648
Book depreciation	222,211,672
Capital leases	4,794,089
Capitalized interest	9,649,630
Deferred cost of electricity	119,450,670
Federal income tax expense	84,552,897
Goodwill amortization	14,472,829
Hazardous waste disposal costs	3,699,966
Merger costs	1,085,662
Energy efficiency	70,688,946
Salvage	324,969
State income taxes	34,862,360
Equity earnings exclusion	4,963,149
Deferred net metering costs	25,988,861
Vehicle amortization	1,396,215
Self insurance	2,472,384
Lobbying expense	593,678
Other items	1,702,661
	609,169,015

WEST:

Income on books not on the return	
Employee compensation and benfits	11,626,549
Current and deferred federal and state income taxes	29,720,122
Bad debt expense	905,103

Other	406,564
Total	42,658,338

Schedule Page: 261 Line No.: 15 Column: b

	EAST	WEST	TOTAL
Income on books not on the return	40,759,325	0	40,759,325

Income on books not on the return

Amortization of ITC	1,151,351
Contribution in aid of construction	3,172,189
Pension and post retirement costs	36,225,635
Life insurance	210,150
	40,759,325

Schedule Page: 261 Line No.: 20 Column: b

	EAST	WEST	TOTAL
Deductions on books not on the return	495,533,393	51,649,783	547,183,176

EAST:

Deductions on return not on books

Tax depreciation	208,913,985
Bonus depreciation	102,276,593
Repairs expense	17,130,701
AFUDC Debt	781,919
AFUDC Equity	14,920,641
Compensation expense	7,058,516
Cost of removal	29,113,467
Bond redemption amortization	85,472
Loss on asset retirement	18,014,731
Mixed service costs	15,410,511
Pension and PBOP payments	4,309,758
Municipal taxes	1,544,657
Storm costs	74,241,935
Uncollectible accounts	694,900
Accrued Maint/Warranty Reserves	153,709
Other items	881,898
	495,533,393

WEST:

Income on books not on the return

Book/Tax Property Differences	49,606,046
Amortization/Deferral of Regulatory Assets/Liabilities	2,043,737
Total	51,649,783

Schedule Page: 261 Line No.: 22 Column: b

	EAST	WEST	TOTAL
Taxable Income	412,631,545	58,439,980	471,071,525

Schedule Page: 261 Line No.: 23 Column: b

EAST:

Taxable income	412,631,545
State adjustment for bonus depreciation	(40,325,797)
Taxable income for state	372,305,748
State Tax @ 8%	- 29,784,460

Schedule Page: 261 Line No.: 27 Column: b

	EAST	WEST	TOTAL
Federal Taxable Income	383,620,985	58,439,980	442,060,965

This company is a member of an affiliated group, Eversource Energy and Subsidiaries, which will file a 2018 consolidated federal Income Tax return on or before October 15, 2019.

Members of the group are:
Eversource Energy
The Connecticut Light and Power Company
The Connecticut Steam Company
Electric Power, Inc.
NGS Sub, Inc.
Harbor Electric Energy Company
Hopkinton LNG Corp.
HWP Company
North Atlantic Energy Corporation
North Atlantic Energy Service Corporation
Northeast Generation Services Company
Northeast Nuclear Energy Company
Eversource Energy Service Company
NSTAR Electric Company
NSTAR Gas Company
NU Enterprises, Inc.
Eversource Energy Transmission Ventures, Inc.
The Nutmeg Power Company
Properties, Inc.
Public Service Company of New Hampshire
Renewable Properties, Inc.
The Rocky River Realty Company
Yankee Energy System, Inc.
Yankee Gas Services Company
Eversource Holdco Corporation
Eversource Water Ventures, Inc.

FOOTNOTE DATA

Eversource Aquarion Holdings, Inc.
Aquarion Company
Homeowner Safety Valve Company
Aquarion Water Company
Aquarion Water Company of New Hampshire
Aquarion Water Capital of Massachusetts, Inc.
Aquarion Water Company of Massachusetts, Inc.
Aquarion Water Company of Connecticut

The above entities are parties to a tax allocation agreement under which taxable subsidiaries do not pay any more taxes than they would have otherwise paid had they filed a separate Company tax return, and subsidiaries generating tax losses, if any, are paid for their losses when utilized.

Schedule Page: 261 Line No.: 30 Column: b

	EAST	WEST	TOTAL
Estimated Federal tax payable @21%	80,560,407	12,272,396	92,832,803

WEST:

Estimated Federal Tax @21%	**12,272,396**
Tax Billed to Affiliate for Stranded Cost	**287,436**
Prior Year Taxes	**2,713,889**
Miscellaneous Credit Adjustment	**(10,997)**
Total	**15,262,724**

Federal Income Tax	**$16,792,446**
Federal Income Tax - Other Income/Deductions (Page 117,line 53)	**($1,529,722)**
Total	**$15,262,724**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.)
Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	NSTAR ELECTRIC (EAST)					
2	FEDERAL					
3	Unemployment 2017	28,575			28,575	
4	Unemployment 2018			28,972	2,344	
5	FICA 2017	578,173			578,173	
6	FICA 2018			4,438,064	3,838,342	
7	Income	4,863,436		49,898,386	81,354,454	
8	Medicare 2017	135,218			135,218	
9	Medicare 2018			1,238,507	1,098,250	
10	Subtotal	5,605,402		55,603,929	87,035,356	
11						
12	STATE OF CONNECTICUT					
13	Insurance Premium Excise			160,212	160,212	
14	Unemployment 2018			62,862	62,862	
15	Subtotal			223,074	223,074	
16						
17	COMMONWEALTH OF					
18	MASSACHUSETTS					
19	Unemployment 2017	65,400			65,400	
20	Unemployment 2018			393,097	176,710	
21	Income		7,420,027	26,535,596	25,424,650	
22	Mass Sales Tax			215,535	171,225	
23	Universal Health 2017	17,148			17,148	
24	Universal Health 2018			43,908	20,257	
25	Subtotal	82,548	7,420,027	27,188,136	25,875,390	
26						
27	LOCAL MASSACHUSETTS					
28	Property 2017	4,642,148			4,642,148	
29	Property 2018			138,700,837	135,581,739	
30	Subtotal	4,642,148		138,700,837	140,223,887	
31						
32	STATE OF NEW					
33	HAMPSHIRE					
34	Unemployment 2018			8,652	8,652	
35	Subtotal			8,652	8,652	
36						
37	DISTRICT OF COLUMBIA					
38	Unemployment 2018			50	50	
39	Subtotal			50	50	
40						
41	TOTAL	12,127,449	7,889,769	274,255,895	309,573,206	-25,940

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.)
Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	NSTAR ELECTRIC (WEST)					
2	FEDERAL					
3	Unemployment 2017	7,355			7,355	
4	Unemployment 2018			6,170	899	
5	FICA 2017	127,464			127,464	
6	FICA 2018			879,917	740,938	
7	Highway			-2,720	-2,720	
8	Income	1,033,757		1,820,190	5,505,269	-25,940
9	Medicare 2017	29,810			29,810	
10	Medicare 2018			235,165	202,662	
11	Subtotal	1,198,386		2,938,722	6,611,677	-25,940
12						
13	STATE OF CONNECTICUT					
14	Unemployment 2018			15,598	15,598	
15	Insurance Premium Excise			35,121	35,121	
16	Corporation Business			-8,220	-8,220	
17	Subtotal			42,499	42,499	
18						
19	COMMONWEALTH OF					
20	MASSACHUSETTS					
21	Unemployment 2017	14,535			14,535	
22	Unemployment 2018			30,604	10,536	
23	Income	579,886		1,614,356	3,609,863	
24	Corporate Excise			-435,000	-435,000	
25	Universal Health 2017	4,544			4,544	
26	Universal Health 2018			9,009	2,075	
27	Subtotal	598,965		1,218,969	3,206,553	
28						
29	LOCAL MASSACHUSETTS					
30	Property 2017		469,742	469,742		
31	Property 2018			47,859,125	46,343,908	
32	Subtotal		469,742	48,328,867	46,343,908	
33						
34	STATE OF NEW					
35	HAMPSHIRE					
36	Unemployment 2018			2,147	2,147	
37	Subtotal			2,147	2,147	
38	DISTRICT OF COLUMBIA					
39	Unemployment 2018			13	13	
40	Subtotal			13	13	
41	TOTAL	12,127,449	7,889,769	274,255,895	309,573,206	-25,940

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
						3
26,628		28,972				4
						5
599,722		4,438,064				6
	26,592,632	59,726,819			-9,828,433	7
						8
140,257		1,238,507				9
766,607	26,592,632	65,432,362			-9,828,433	10
						11
						12
		160,212				13
		62,862				14
		223,074				15
						16
						17
						18
						19
216,387		393,097				20
	6,309,081	26,298,359			237,237	21
44,310		215,535				22
						23
23,651		43,908				24
284,348	6,309,081	26,950,899			237,237	25
						26
						27
						28
3,119,098		138,451,501			249,337	29
3,119,098		138,451,501			249,337	30
						31
						32
						33
		8,652				34
		8,652				35
						36
						37
		50				38
		50				39
						40
5,889,025	36,942,716	298,994,681			-24,738,786	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
						3
5,271		6,170				4
						5
138,979		879,916				6
		-2,720				7
	2,625,382	16,792,446			-14,972,256	8
						9
32,503		235,165				10
176,753	2,625,382	17,910,977			-14,972,256	11
						12
						13
		15,598				14
		35,121				15
		-8,220				16
		42,499				17
						18
						19
						20
						21
20,068		30,604				22
	1,415,621	2,259,530			-645,174	23
		-435,000				24
						25
6,934		9,009				26
27,002	1,415,621	1,864,143			-645,174	27
						28
						29
		469,742				30
1,515,217		47,638,622			220,503	31
1,515,217		48,108,364			220,503	32
						33
						34
						35
		2,147				36
		2,147				37
						38
		13				39
		13				40
5,889,025	36,942,716	298,994,681			-24,738,786	41

Schedule Page: 262 Line No.: 7 Column: l

Total includes $218,120 for non-operating taxes account 409.2; and $9,610,313 for solar tax credits reclassed from account 236 to account 255 (Accumulated Deferred Investment Tax Credits).

Schedule Page: 262 Line No.: 21 Column: l

State of Massachusetts income taxes apportioned to other income account 409.2.

Schedule Page: 262 Line No.: 29 Column: i

Information on Formula Rates:

Page 106 lines 26, 30, 35	Town specific local taxes.
Page 106.1 lines 1, 8, 15, 20, 27,34	Town specific local taxes.
Page 106.2 line 29	Town specific local taxes.
Page 106.2 lines 1, 5	Amount stipulated per contract.

Schedule Page: 262 Line No.: 29 Column: l

Non-utility real estate and personal property tax assigned to account 408.2.

Schedule Page: 262.1 Line No.: 4 Column: i

Federal unemployment taxes charged to operating expense includes a transmission related component of $209.

Schedule Page: 262.1 Line No.: 5 Column: b

FICA taxes include a transmission related component of $6,908 credit.

Schedule Page: 262.1 Line No.: 6 Column: g

FICA taxes include a transmission related component of $8,091 credit.

Schedule Page: 262.1 Line No.: 6 Column: i

FICA taxes charged to operating expense includes a transmission related component of $28,072.

Schedule Page: 262.1 Line No.: 8 Column: b

Federal income taxes include a transmission component of $1,027,364 credit.

Schedule Page: 262.1 Line No.: 8 Column: f

Adjustment for tax billed to affiliate for stranded cost.

Schedule Page: 262.1 Line No.: 8 Column: h

Federal income taxes include a transmission component of $7,932,969 credit.

Schedule Page: 262.1 Line No.: 8 Column: i

Federal income taxes charged to operating expense includes a transmission related component of $10,007,283.

Schedule Page: 262.1 Line No.: 8 Column: l

Total includes $1,529,722 for non-operating taxes, of which $882,821 in transmission related; and $13,442,534 for solar tax credits reclassed from account 236 to account 255 (Accumulated Deferred Investment Tax Credits).

Schedule Page: 262.1 Line No.: 9 Column: b

Medicare taxes include a transmission related component of $1,616 credit.

Schedule Page: 262.1 Line No.: 10 Column: g

Medicare taxes include a transmission related component of $1,892 credit.

Schedule Page: 262.1 Line No.: 10 Column: i

Medicare taxes charged to operating expense includes a transmission related component of $7,961.

Schedule Page: 262.1 Line No.: 14 Column: i

State of Connecticut unemployment taxes charged to operating expense includes a transmission related component of $1,092.

Schedule Page: 262.1 Line No.: 15 Column: i

State of Connecticut insurance premium excise taxes charged to operating expense includes

a transmission related component of $15,540.

Schedule Page: 262.1 Line No.: 16 Column: i

State of Connecticut Corporation Business Taxes charged to operating expense includes a transmission related component of $141.

Schedule Page: 262.1 Line No.: 22 Column: i

Commonwealth of Massachusetts unemployment taxes charged to operating expense includes a transmission related component of $897.

Schedule Page: 262.1 Line No.: 23 Column: b

Commonwealth of Massachusetts corporate income taxes include a transmission related component of $238,322 credit.

Schedule Page: 262.1 Line No.: 23 Column: h

Commonwealth of Massachusetts corporate income taxes include a transmission related component of $1,524,190 debit.

Schedule Page: 262.1 Line No.: 23 Column: i

Commonwealth of Massachusetts corporate income taxes charged to operating expense includes a transmission related component of $443,268.

Schedule Page: 262.1 Line No.: 23 Column: l

Commonwealth of Massachusetts corporate income taxes include a transmission related component of $365,584 credit.

Schedule Page: 262.1 Line No.: 24 Column: i

No transmission component of tangible tax in 2018.

Schedule Page: 262.1 Line No.: 26 Column: i

Commonwealth of Massachusetts universal health taxes charged to operating expense includes a transmission related component of $185.

Schedule Page: 262.1 Line No.: 30 Column: c

Massachusetts local property taxes include a distribution component of $808,794 debit and a transmission component of $339,052 credit.

Schedule Page: 262.1 Line No.: 31 Column: g

Massachusetts local property taxes include a distribution component of $625,855 credit and a transmission component of $889,362 credit.

Schedule Page: 262.1 Line No.: 31 Column: l

Massachusetts local property tax expense charged to other accounts include $62,755 to account 184, $87,394 to account 408.2 and $70,354 to account 163. Included in account 408.2 is a transmission related component of $58,708.

Schedule Page: 262.1 Line No.: 32 Column: i

Local Property Tax - D	21,585,416.78
Local Property Tax - T	26,522,946.92
	48,108,363.70

Information on Formula Rates:

Calculated per company records as stipulated per contract.

Page 106.3 line 23

Schedule Page: 262.1 Line No.: 36 Column: i

State of New Hampshire unemployment taxes charged to operating expense includes a transmission related component of $150.

Schedule Page: 262.1 Line No.: 39 Column: i

District of Columbia unemployment taxes charged to operating expense includes a transmission related component of $1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%	33			411.4	22	
3	4%	585,735			411.4	117,160	
4	7%						
5	10%	2,119,364			411.4	902,198	
6	Solar Credit-West	7,737,152			411.4	394,752	
7	Solar Expansion Cre			23,052,847	411.4	345,475	
8	TOTAL	10,442,284		23,052,847		1,759,607	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Sale/leaseback-East	229,150			411.4	29,576	
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
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47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
11			2
468,575			3
			4
1,217,166			5
7,342,400			6
22,707,372			7
31,735,524			8
			9
			10
199,574			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
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			45
			46
			47
			48

Schedule Page: 266 Line No.: 8 Column: b

West - At the beginning of the year, the balance of Accumulated Deferred Investment Tax Credits in Account 255 includes a transmission component of $2,420.

Schedule Page: 266 Line No.: 8 Column: f

West - The amount charged to Account 411.4 includes a transmission related component of $1,524 for the year ended December 31, 2018.

Schedule Page: 266 Line No.: 8 Column: h

EAST	WEST	TOTAL
11,381,373	20,553,725	31,935,098

EAST :

Line No	Account Subdivisions a	Balance at Beginning of Year b	Deferred for year		Alloc to Income		Adjustments g	Balance at End of Year h
			Amount d		Amount f			
1	Electric Utility							
2	3%	-			-			-
3	4%	585,512			117,022			468,490
4	7%							-
5	10%	2,107,749			894,990			1,212,759
6	Sale leaseback	229,150			29,576			199,574
7	Solar Expansion Credit	-	9,610,313		109,763			9,500,550
8	TOTAL	2,922,411	9,610,313		1,151,351			11,381,373
9	Other							

WEST:

Line No	Account Subdivisions a	Balance at Beginning of Year b	Deferred for Year		Alloc to Income		Adjustments g	Balance at End of Year h
			Amount d		Amount f			
1	Electric Utility							
2	3%	33			22			11
3	4%	223			138			85
4	7%							-
5	10%	11,615			7,208			4,407
6	Solar Credit	7,737,152			394,752			7,342,400
7	Solar Expansion Credit	-	13,442,534		235,712			13,206,822
8	TOTAL	7,749,023	13,442,534		637,832			20,553,725
9	Other							

FOOTNOTE DATA

Line 8, column b
West - Note that at the beginning of the year, the balance of Accumulated Deferred Investment Tax Credits in Account 255 includes a transmission component of $2,420.

Line 8, column f
West - The amount charged to Account 411.4 includes a transmission related component of $1,524 for the year ended December 31, 2018.

Line 8, column h
West - Note that at the end of the year, the balance of Accumulated Deferred Investment Tax Credits in Account 255 includes a transmission related component of $896.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Decommissioning obligations	1,435,366	242/182	77,885	38,540	1,396,021
2						
3	Disputed property taxes	30,074,318			9,628,837	39,703,155
4						
5	Sale of property clearing	976,791	232	217		976,574
6						
7	Warranty work - electric breakers	94,461	242	6,663		87,798
8						
9	Escheatable monies	2,509,758	232	1,775,729	1,594,277	2,328,306
10						
11	Clean energy bids	1,517,262	254	4,249,881	3,429,212	696,593
12						
13	Contributions in Aid of					
14	Construction-Tax Gross-up					
15	(20 year amortization)	5,665,440	186	26,543,601	27,942,611	7,064,450
16						
17	MATEP Distribution Study				410,512	410,512
18						
19	Minor items	118,556	232	3,842		114,714
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	42,391,952		32,657,818	43,043,989	52,778,123

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Account 282			
2	Electric	1,191,923,425	58,109,220	1,790,342
3	Gas			
4	Transition property			
5	TOTAL (Enter Total of lines 2 thru 4)	1,191,923,425	58,109,220	1,790,342
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,191,923,425	58,109,220	1,790,342
10	Classification of TOTAL			
11	Federal Income Tax	969,568,946	37,201,152	1,314,937
12	State Income Tax	222,354,479	20,908,068	475,405
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
				182/254 .	13,231,406	1,261,473,709	2
							3
							4
					13,231,406	1,261,473,709	5
							6
							7
							8
					13,231,406	1,261,473,709	9
							10
					14,001,541	1,019,456,702	11
					-770,135	242,017,007	12
							13

NOTES (Continued)

Schedule Page: 274 Line No.: 9 Column: b

EAST	WEST	TOTAL
889,610,050	302,313,375	1,191,923,425

WEST:
At the beginning of the year, the total balance of Accumulated Deferred Income Taxes in account 282 includes a transmission related component of $184,905,974.In addition, Account 254 includes a transmission related component of $104,382,688 transferred from this account as a result of the Federal Income Tax Act.

Schedule Page: 274 Line No.: 9 Column: k

EAST	WEST	TOTAL
945,081,038	316,392,671	1,261,473,709

EAST:
Information on Formula Rates Page 106.2 line 1:
Amount as stipulated per contract.

Account 282 balance per balance sheet	$ 945,081,038
ASC740 deferred income taxes (FAS109)	494,564,499
Transmission billing (sheet 3, line 16, col. c)	$1,439,645,537

WEST:
At the end of the year, the total balance of Accumulated Deferred Income Taxes in account 282 includes a transmission related component of $194,260,538.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3		484,036,684	82,986,382	48,382,842
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	484,036,684	82,986,382	48,382,842
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other Income and deductions	2,473,568		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	486,510,252	82,986,382	48,382,842
20	Classification of TOTAL			
21	Federal Income Tax	372,443,810	58,747,302	34,217,848
22	State Income Tax	114,066,442	24,239,080	14,164,994
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	
							1
							2
		182/254	88,306,764		74,793,379	505,126,839	3
							4
							5
							6
							7
							8
			88,306,764		74,793,379	505,126,839	9
							10
							11
							12
							13
							14
							15
							16
							17
468	20,420					2,453,616	18
468	20,420		88,306,764		74,793,379	507,580,455	19
							20
468	14,460		78,831,212		54,092,686	372,220,746	21
	5,960		9,475,552		20,700,693	135,359,709	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 3 Column: b

The disclosure required by FERC Policy Statement PL 19-2-000 is included as a footnote to page 278, Account 254.

EAST	WEST	TOTAL
421,399,236	62,637,448	484,036,684

Schedule Page: 276 Line No.: 9 Column: k

EAST	WEST	TOTAL
441,366,030	63,760,809	505,126,839

Schedule Page: 276 Line No.: 18 Column: b

EAST	WEST	TOTAL
0	2,473,568	2,473,568

Schedule Page: 276 Line No.: 18 Column: k

EAST	WEST	TOTAL
0	2,453,616	2,453,616

Schedule Page: 276 Line No.: 19 Column: b

EAST	WEST	TOTAL
421,399,236	65,111,016	486,510,252

WEST:

At the beginning of the year, the total balance of Accumulated Deferred Income Taxes in Account 283 includes a transmission related component of $6,488,383. In addition, Account 254 includes a transmission related component of $42,622,745 transferred from this account as a result of the Federal Income Tax Act.

Schedule Page: 276 Line No.: 19 Column: k

EAST	WEST	TOTAL
441,366,030	66,214,425	507,580,455

EAST:

Performance reward program	$ 1,536,020	All (Labor)
Bond redemption call premiums	2,852,045	All (Plant)
Pension expense	138,559,388	All (Labor)
Post employment benefits accrued	37,245,182	All (Labor)
Hazardous waste reserves	2,180,423	All (Plant)
Property tax lien date accrual	19,555,401	All (Plant)
Workers compensation gross up payable	4,801,981	All (Labor)

Retail adjuster clause deferrals	39,596,017	Retail Adjuster Clause
Keep cost receivable	10,361,383	Distribution
Storm contingency fund	58,636,044	Distribution
Rate change to 21% in account 283	49,065,168	All (Labor)
Rate change to 21% in account 283	12,104,031	All (Plant)
Rate change to 21% in account 283	20,548,094	Distribution
Rate change to 21% in account 283	16,869,770	Retail Adjuster Clause
ASC 740 deferred income taxes (FAS109)	(60,179,683)	All (Plant)
Goodwill	81,715,431	Regulatory Asset
Other items	5,919,335	All (Plant)
Total	$441,366,030	

Information on Formula Rates Page 106.2 line 1:
Amount as stipulated by contract.

WEST:

	Beginning Balance	Activity	Ending Balance
ASC 740 Gross-Up (FAS 109)	$ 14,435,534	$ (545,014)	$ 13,890,520
ASC 740 Regulatory Asset (FAS 109)	(10,051,924)	(1,562,403)	(11,614,327)
Property Taxes	2,356,891	593,897	2,950,788
Regulatory Deferrals	56,364,640	398,512	56,763,152
Employee Benefits	409,256	860,134	1,269,390
Asset Retirement Obligations	1,170,196	164,365	1,334,561
Other	426,423	1,193,918	1,620,341
TOTAL ACCOUNT 283	$ 65,111,016	$ 1,103,409	$ 66,214,425

Note that at the beginning of the year, the total balance of Accumulated Deferred Income Taxes in Account 283 includes a transmission related component of $6,488,383.

Note that at the end of the year, the total balance of Accumulated Deferred Income Taxes in Account 283 includes a transmission related component of $6,095,274.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Federal income tax rate change	1,087,794,687	190	506,385	16,384,423	1,103,672,725
2						
3	FASB ASC 740 Regulatory Liability	6,332,125			3,690,377	10,022,502
4						
5	AFUDC recorded on transmission	18,310,445	407.4	491,782	5,511,258	23,329,921
6	construction work in progress					
7						
8	Transition Reconciliation					
9	D.P.U. 96-23, 97-111, 97-120					
10	This account captures the difference between					
11	costs incurred related to the transition charge					
12	and the amounts actually billed to customers	6,638,904	407.3/431	7,567,252	2,318,508	1,390,160
13						
14	Transmission Reconciliation: D.P.U. 06-40, 97-120					
15	The Company defers the difference between					
16	the transmission revenues billed to customers					
17	and the cost to provide transmission service.	20,691,339	565	7,076,070	79,782,704	93,397,973
18						
19	Pension and PBOP:					
20	D.P.U. 03-47, 06-55					
21	which requires the Company to defer					
22	pension and PBOP expense that exceeds the					
23	current rate recovery. Each year's deferred					
24	amount is amortized over the subsequent three					
25	year period.	43,542,836	Footnote	44,538,454	38,162,436	37,166,818
26						
27	Pension and PBOP ASC 715	112,573,795	128	35,677,043		76,896,752
28						
29	Basic Service Cost Adjustment D.P.U. 03-88-A-F	101,417	407.4/431	450,629	178,245	-170,967
30						
31	Solar Program D.P.U. 09-05	331,237	182.3	331,237		
32						
33	Revenue Decoupling D.P.U. 17-05				3,502,563	3,502,563
34						
35	Storm Fund Post 2-1-18 D.P.U. 17-05				6,989,347	6,989,347
36						
37	Basic Service Reconciliation: D.P.U. 06-40					
38	The Company defers the cost to					
39	provide service to customers compared					
40	to amounts billed to customers, plus carrying					
41	TOTAL	1,296,363,587		96,675,007	174,590,693	1,374,279,273

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	charges				4,389,972	4,389,972
2						
3	Deferred net metering costs D.P.U. 12-116				12,735,129	12,735,129
4						
5	Uncollectibles Associated with Basic Service					
6	D.P.U. 03-88A				181,536	181,536
7						
8	Minor items	46,802	407.3	36,155	764,195	774,842
9						
10						
11						
12						
13						
14						
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36						
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38						
39						
40						
41	TOTAL	1,296,363,587		96,675,007	174,590,693	1,374,279,273

Schedule Page: 278 Line No.: 1 Column: f

East Distribution	$ 850,142,721
West Distribution	106,349,849
West Transmission	147,180,155
Total	$1,103,672,725

On December 22, 2017, the President signed into law the Tax Cuts and Jobs Act. The Tax Cuts and Jobs Act, among other things, reduced the federal corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018. This means that, beginning January 1, 2018, companies subject to the Commission's jurisdiction will compute income taxes owed to the Internal Revenue Service based on a 21 percent tax rate. The tax rate reduction will result in less corporate income tax expense going forward.

(1) In accounting for the impact of the income tax rate change, FERC accounts 190, 282, and 283 were reduced to reflect lower required balances in Accumulated Deferred Income Taxes ("ADIT"). The offsetting entry was to account 182.3 and 254.

(2) The affected ADIT accounts were remeasured by comparing ADIT on cumulative temporary differences for each item in accounts 190, 282, and 283 at a Federal income rate of 21% to the ADIT at 35%. The difference between the two represents the excess ADIT.

(3) The related amounts associated with the reversal and elimination of ADIT balances in these accounts at December 31, 2018 are as follows:

	Unprotected 190 and 283	Protected 282	Revenue Requirement Adjustment	Total ADIT Decrease
Distribution	170,137,126	402,119,180	209,464,970	$ 781,721,276
Transmission	12,210,411	264,305,451	112,975,415	389,491,277
Sub- total ADIT Reduction	182,347,537	666,424,631	322,440,385	1,171,212,553
Reduction to 182.3 Goodwill				(67,539,828)
Total				$ 1,103,672,725

Transmission excess ADIT for East is in accounts 190 and 283 is allocated at 9.419% and in account 282 at 31.874%. Transmission excess ADIT for West is on a direct charge method. These methods are consistent with the methodologies in the FERC tariff for each of the divisions.

(4) The amount of excess ADIT that is protected and unprotected is included in the table in item 3.

(5) The excess ADIT is amortized to account 411.1.

(6) The amortization period of the excess ADIT to be refunded through rates ranges from 5 years to 10 years for unprotected ADIT. Protected ADIT will be refunded using the Average Rate Assumption

Method.

WEST:

Information on Formula Rates:

Page 106.3 line 9

Calculated per company records and in accordance with Schedule 21-ES, Attachment H under ISO New England Inc. Transmission, Markets and Services Tariff, Section II

Schedule Page: 278 Line No.: 3 Column: f

West Distribution	$10,021,446
West Transmission	1,056
Total	$10,022,502

Schedule Page: 278 Line No.: 5 Column: f

East Transmission	$14,951,855
West Transmission	8,378,066
Total	$23,329,921

Schedule Page: 278 Line No.: 25 Column: c

Account:	Amount:
456	$23,859,413
926	19,730,000
440	949,041
Total	$44,538,454

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	1,383,550,022	1,269,750,366
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,375,030,078	1,264,358,707
5	Large (or Ind.) (See Instr. 4)	124,894,540	113,966,319
6	(444) Public Street and Highway Lighting	14,599,693	14,598,873
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	2,898,074,333	2,662,674,265
11	(447) Sales for Resale	73,125,096	77,087,381
12	TOTAL Sales of Electricity	2,971,199,429	2,739,761,646
13	(Less) (449.1) Provision for Rate Refunds	-5,255,654	2,998,459
14	TOTAL Revenues Net of Prov. for Refunds	2,976,455,083	2,736,763,187
15	Other Operating Revenues		
16	(450) Forfeited Discounts	4,510,904	4,317,226
17	(451) Miscellaneous Service Revenues	1,611,900	315,790
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	14,484,140	13,077,370
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-4,944,948	86,484,270
22	(456.1) Revenues from Transmission of Electricity of Others	367,750,994	371,595,751
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	383,412,990	475,790,407
27	TOTAL Electric Operating Revenues	3,359,868,073	3,212,553,594

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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
8,181,727	7,720,675	1,230,516	1,221,799	2
				3
14,028,514	14,021,451	185,601	184,743	4
1,687,971	1,691,321	1,760	1,801	5
101,172	104,986	9,668	9,679	6
				7
				8
				9
23,999,384	23,538,433	1,427,545	1,418,022	10
1,262,293	1,680,697	17	17	11
25,261,677	25,219,130	1,427,562	1,418,039	12
				13
25,261,677	25,219,130	1,427,562	1,418,039	14

Line 12, column (b) includes $ -14,987,833 of unbilled revenues.

Line 12, column (d) includes -94,427 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 4 Column: b

Commercial

Schedule Page: 300 Line No.: 5 Column: b

Industrial

Schedule Page: 300 Line No.: 10 Column: d

Instruction 9 - Unmetered Sales (MWH)

Customer Class	East	West	Total
Residential	1,038	1,700	2,738
Commercial	5,995	10,744	16,739
Industrial	28	1,396	1,424
Street Light	80,458	18,430	98,888
Total	**87,519**	**32,270**	**119,789**

The total "Megawatt Hours Sold" to retail customers represents the delivery of energy to all distribution customers including energy for those customers who have chosen third party suppliers.

Schedule Page: 300 Line No.: 17 Column: b

Description	East	West	Total
Reconnect Fees	$ 918,800	$ 259,207	$ 1,178,007
Return Check Fees	362,270	61,111	423,381
Other Service Fees	49,824	(39,312)	10,512
Total	**$ 1,330,894**	**$ 281,006**	**$ 1,611,900**

Schedule Page: 300 Line No.: 19 Column: b

Description	East	West	Total
Associated Company Rents	$ 1,654,589		$ 1,654,589
Pole Attachment Rents	5,045,625	$ 474,956	5,520,581
Distribution - Wireless and Other Rents	2,424,141	565,792	2,989,933
Transmission - Wireless and Other Rents	3,816,219	502,818	4,319,037
Total	**$ 12,940,574**	**$ 1,543,566**	**$ 14,484,140**

Schedule Page: 300 Line No.: 21 Column: b

Description	East	West	Total
Energy Efficiency Revenue	$ 6,998,810		$ 6,998,810
Renewable Energy Certificates		$ 2,971,222	2,971,222
MBTA distribution facilities	2,394,957		2,394,957
MATEP distribution	1,654,568		1,654,568
Massport distribution facilities	2,656,631		2,656,631
PAM carrying charge	4,247,413	56,404	4,303,817
Enhanced billing & metering services	304,797		304,797
Net metering revenue	(33,000,874)		(33,000,874)
Solar Expansion	1,194,281	2,710,788	3,905,069
Local facility charges		323,448	323,448
Wholesale distribution services		2,244,242	2,244,242
Other revenue	298,365		298,365
Total	**$(13,251,052)**	**$ 8,306,104**	**$ (4,944,948)**

EAST:

Page 106 lines 10 and 13 Terms stipulated per contract.

Schedule Page: 300 Line No.: 22 Column: b

Refer to Pages 328-330 for detail.

FOOTNOTE DATA

EAST:

Information on Formula Rates:

Page 106 lines 10, 13, 23, 26, 30, 35	Terms stipulated per contract.
Page 106.1 lines 1, 8, 15, 20, 27, 34	Terms stipulated per contract.
Page 106.2 lines 1, 5	Terms stipulated per contract.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	Not Applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
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38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential (Account 440)					
2	All Service Areas					
3	R-1 Residential	6,408,282	1,160,481,879	1,009,426	6,348	0.1811
4	R-2 Residential Assistance	734,459	64,419,504	119,048	6,169	0.0877
5	R-3 Res. Space Heating	885,614	150,357,940	90,398	9,797	0.1698
6	R-4 Res. Space Heating Assist.	89,160	8,028,390	7,195	12,392	0.0900
7	S-1 Street Lighting	2,205	594,416	2,137	1,032	0.2696
8	S-2 Street Lighting Cust Owned	532	42,314	12	44,333	0.0795
9	West					
10	23 Optional Water Heating	166	17,130	6	27,667	0.1032
11	T-0 Small General Service TOU	11	949	1	11,000	0.0863
12	T-2 Large Primary Service TOU	14,489	1,093,122	8	1,811,125	0.0754
13	G-0 Small General Service	30,774	5,095,635	3,321	9,266	0.1656
14	G-2 Primary General Service	44,456	3,929,729	96	463,083	0.0884
15	99 Unmetered	1	328	1	1,000	0.3280
16	Unbilled Revenue	-28,422	-10,511,314			0.3698
17	less: Duplicate Customers			-1,133		
18	Total Residential	8,181,727	1,383,550,022	1,230,516	6,649	0.1691
19						
20	Commercial (Account 442)					
21	All Service Areas					
22	R-1 Residential	17,415	2,141,436	2,751	6,330	0.1230
23	R-3 Res. Space Heating	3,789	419,555	72	52,625	0.1107
24	S-1 Street Lighting	15,372	2,638,517	5,916	2,598	0.1716
25	S-2 Street Lighting Cust Owned	143	4,540	14	10,214	0.0317
26	Greater Boston					
27	G-1 General Service	524,266	94,880,592	74,325	7,054	0.1810
28	G-2 General Service	2,594,552	363,499,929	28,703	90,393	0.1401
29	G-3 General Service TOU	2,305,084	159,767,456	348	6,623,805	0.0693
30	T-1 Optional Time of Use	1,426	30,969	201	7,095	0.0217
31	T-2 Time of Use	3,878,999	364,829,010	3,023	1,283,162	0.0941
32	WR MWRA	104,131	3,772,286	2	52,065,500	0.0362
33	SB-G3 Gen. Service Standby	17,466	1,163,712	1	17,466,000	0.0666
34	Contract-Amtrak Transmission	40,766	1,239,830	1	40,766,000	0.0304
35	Cambridge					
36	G-0 General (Non-Demand)	37,937	3,909,663	5,278	7,188	0.1031
37	G-1 General	204,838	18,094,618	2,000	102,419	0.0883
38	G-2 Lg. Gen. TOU/Second Serv	569,236	39,397,508	461	1,234,785	0.0692
39	G-3 Lg. Gen. TOU/13.8KV Serv	479,945	22,218,133	72	6,665,903	0.0463
40	G-4 Optional General TOU	5,008	369,253	36	139,111	0.0737
41	TOTAL Billed	24,093,811	2,913,062,166	1,427,545	16,878	0.1209
42	Total Unbilled Rev.(See Instr. 6)	-94,427	-14,987,833	0	0	0.1587
43	TOTAL	23,999,384	2,898,074,333	1,427,545	16,812	0.1208

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	G-5 Commercial Space Heating	6,655	535,216	57	116,754	0.0804
2	G-6 Opt. Gen. TOU (Non-Demand)		822			
3	SB-1 Standby Service	27,788	1,448,509	1	27,788,000	0.0521
4	MS-1 Maintenance Service	25,983	590,249	1	25,983,000	0.0227
5	SS-1 Supplemental Service	51,866	3,219,748	1	51,866,000	0.0621
6	SB-G3 Gen. Service Standby	33,514	3,238,737	1	33,514,000	0.0966
7	Contract-MIT MAG Lab	690	136,502	1	690,000	0.1978
8	South Shore / Cape & Vineyard					
9	G-1 General	983,055	97,313,196	44,957	21,867	0.0990
10	G-2 Med. General Time of Use	412,826	29,312,190	419	985,265	0.0710
11	G-3 Lg. General Time of Use	232,141	15,633,448	52	4,464,250	0.0673
12	G-4 General Power	1,239	103,302	15	82,600	0.0834
13	G-5 Commercial Space Heating	12,831	1,371,879	742	17,292	0.1069
14	G-6 All-Electric School	4,738	289,492	7	676,857	0.0611
15	G-7 Optional General TOU	55,191	4,457,166	604	91,376	0.0808
16	West					
17	23 Optional Water Heating	20	6,409	16	1,250	0.3205
18	24 Optional Church	6,076	877,387	191	31,812	0.1444
19	T-0 Small General Service TOU	1,608	129,586	12	134,000	0.0806
20	T-2 Large Primary Service TOU	431,944	30,045,252	158	2,733,823	0.0696
21	T-4 Primary General Service TOU	7,094	587,639	12	591,167	0.0828
22	T-5 Extra Lg. Primary Service TOU	179,137	11,779,548	9	19,904,111	0.0658
23	G-0 Small General Service	537,082	75,106,286	17,249	31,137	0.1398
24	G-2 Primary General Service	274,500	23,904,025	747	367,470	0.0871
25	99 Unmetered	1,224	116,713	104	11,769	0.0954
26	Unbilled Revenue	-59,061	-3,550,230			0.0601
27	less: Duplicate Customers			-2,959		
28	Total Commercial	14,028,514	1,375,030,078	185,601	75,584	0.0980
29						
30	Industrial (Account 442)					
31	All Service Areas					
32	S-1 Street Lighting	1,424	180,501	185	7,697	0.1268
33	Greater Boston					
34	G-1 General Service	1,434	194,627	154	9,312	0.1357
35	G-2 General Service	46,361	7,210,144	485	95,590	0.1555
36	G-3 General Service TOU	655,189	46,525,147	114	5,747,272	0.0710
37	T-2 Time of Use	114,112	13,082,544	120	950,933	0.1146
38	Cambridge					
39	G-0 General (Non-Demand)	25	2,491	5	5,000	0.0996
40	G-2 Lg. Gen. TOU/Second Serv	2,280	194,248	4	570,000	0.0852
41	TOTAL Billed	24,093,811	2,913,062,166	1,427,545	16,878	0.1209
42	Total Unbilled Rev.(See Instr. 6)	-94,427	-14,987,833	0	0	0.1587
43	TOTAL	23,999,384	2,898,074,333	1,427,545	16,812	0.1208

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	G-3 Lg. Gen. TOU/13.8KV Serv	21,539	1,167,935	6	3,589,833	0.0542
2	South Shore / Cape & Vineyard					
3	G-1 General	9,534	1,025,038	120	79,450	0.1075
4	G-2 Med. General Time of Use	44,457	3,700,876	57	779,947	0.0832
5	G-3 Lg. General Time of Use	173,700	9,481,562	35	4,962,857	0.0546
6	G-4 General Power	1,092	113,294	13	84,000	0.1037
7	G-7 Optional General TOU	129	17,450	4	32,250	0.1353
8	Contract-Canal	14,499	1,951,736	2	7,249,500	0.1346
9	West					
10	T-0 Small General Service TOU	117	14,197	2	58,500	0.1213
11	T-2 Large Primary Service TOU	265,753	17,631,449	71	3,743,000	0.0663
12	T-4 Primary General Service TOU	1,528	178,552	5	305,600	0.1169
13	T-5 Extra Lg. Primary Service TOU	260,943	14,339,751	6	43,490,500	0.0550
14	G-0 Small General Service	25,060	3,358,409	393	63,766	0.1340
15	G-2 Primary General Service	55,805	5,453,318	157	355,446	0.0977
16	Unbilled Revenue	-7,010	-928,729			0.1325
17	less: Duplicate Customers			-178		
18	Total Industrial	1,687,971	124,894,540	1,760	959,074	0.0740
19						
20	Street Lighting (Account 444)					
21	All Service Areas					
22	S-1 Street Lighting	37,699	9,268,265	3,758	10,032	0.2458
23	S-2 Street Lighting Cust Owned	61,094	5,002,735	5,117	11,939	0.0819
24	Cambridge					
25	G-0 General (Non-Demand)	917	113,660	228	4,022	0.1239
26	G-1 General	135	12,956	4	33,750	0.0960
27	South Shore / Cape & Vineyard					
28	G-1 General	1,158	177,069	513	2,257	0.1529
29	West					
30	G-0 Small General Service	8	2,075	5	1,600	0.2594
31	99 Unmetered	95	20,493	43	2,209	0.2157
32	Unbilled Revenue	66	2,440			0.0370
33	Total Street Lighting	101,172	14,599,693	9,668	10,465	0.1443
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	24,093,811	2,913,062,166	1,427,545	16,878	0.1209
42	Total Unbilled Rev.(See Instr. 6)	-94,427	-14,987,833	0	0	0.1587
43	TOTAL	23,999,384	2,898,074,333	1,427,545	16,812	0.1208

FOOTNOTE DATA

Schedule Page: 304 Line No.: 1 Column: a

MWh Sold (Column b) represents all energy deliveries to customers. Revenues (Column c) include delivery revenues as well as energy revenues for those customers who receive their energy supply from NSTAR Electric Company via Basic Service. Since revenues do not include the supply cost to customers of competitive energy suppliers, revenue per KWh sold (Column f) is not necessarily representative of the average customer bill.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1						
2	Requirement Service:					
3	The Connecticut Light and Power Company	RQ	10			
4	National Grid	RQ	2			
5	New York State Electric & Gas Corp.	RQ	2			
6						
7	Nonassociated Utilities/Companies					
8	ISO-New England	OS	10			
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
					1
					2
49		5,069	5,904	10,973	3
182		22,063	13,512	35,575	4
45	3,382	1,919		5,301	5
					6
					7
1,262,017		48,152,280	24,920,967	73,073,247	8
					9
					10
					11
					12
					13
					14
276	3,382	29,051	19,416	51,849	
1,262,017	0	48,152,280	24,920,967	73,073,247	
1,262,293	**3,382**	**48,181,331**	**24,940,383**	**73,125,096**	

FOOTNOTE DATA

Schedule Page: 310 Line No.: 3 Column: a

Associated Utility

Schedule Page: 310 Line No.: 3 Column: c

MBR FERC Electric Tariff, Third Revised Vol. No. 10, 1.0.0

Schedule Page: 310 Line No.: 4 Column: c

NSTAR - FERC Electric Tariff Original Volume No. 2

Schedule Page: 310 Line No.: 8 Column: b

Short-term energy and capacity sales.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)		
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)		
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)		
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

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NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	23,844	23,831
63	(547) Fuel		
64	(548) Generation Expenses	247,527	189,007
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	271,371	212,838
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	271,371	212,838
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,059,530,159	836,223,072
77	(556) System Control and Load Dispatching	961,586	1,002,932
78	(557) Other Expenses	56,732	10,216,095
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	1,060,548,477	847,442,099
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,060,819,848	847,654,937
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,096,851	5,425,056
84			
85	(561.1) Load Dispatch-Reliability	1,148,881	1,166,148
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,025,018	1,020,373
87	(561.3) Load Dispatch-Transmission Service and Scheduling	510,333	505,584
88	(561.4) Scheduling, System Control and Dispatch Services	14,257,125	15,142,905
89	(561.5) Reliability, Planning and Standards Development	1,725,304	1,701,943
90	(561.6) Transmission Service Studies	684,619	733,592
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	19,593	17,323
93	(562) Station Expenses	4,349,658	2,949,209
94	(563) Overhead Lines Expenses	2,146,390	534,469
95	(564) Underground Lines Expenses	4,953,941	5,078,340
96	(565) Transmission of Electricity by Others	414,526,625	405,297,157
97	(566) Miscellaneous Transmission Expenses	240,115	367,240
98	(567) Rents	91,574	75,693
99	TOTAL Operation (Enter Total of lines 83 thru 98)	451,776,027	440,015,032
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	401,228	416,760
102	(569) Maintenance of Structures	558,414	406,031
103	(569.1) Maintenance of Computer Hardware	315,855	519,180
104	(569.2) Maintenance of Computer Software	616,994	638,095
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,129,469	1,952,781
108	(571) Maintenance of Overhead Lines	10,438,202	9,562,414
109	(572) Maintenance of Underground Lines	-101,422	8,232,725
110	(573) Maintenance of Miscellaneous Transmission Plant	595	317
111	TOTAL Maintenance (Total of lines 101 thru 110)	15,359,335	21,728,303
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	467,135,362	461,743,335

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	278,766	427,859
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	278,766	427,859
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	278,766	427,859
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	13,683,293	14,947,049
135	(581) Load Dispatching	4,161,234	5,309,236
136	(582) Station Expenses	5,910,675	6,006,577
137	(583) Overhead Line Expenses	12,982,143	11,465,332
138	(584) Underground Line Expenses	14,690,084	10,285,360
139	(585) Street Lighting and Signal System Expenses	995,890	916,291
140	(586) Meter Expenses	1,374,080	1,785,117
141	(587) Customer Installations Expenses	1,356,747	1,231,047
142	(588) Miscellaneous Expenses	6,744,017	2,827,087
143	(589) Rents	519,973	1,374,040
144	TOTAL Operation (Enter Total of lines 134 thru 143)	62,418,136	56,147,136
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	287,512	418,451
147	(591) Maintenance of Structures	342,764	407,960
148	(592) Maintenance of Station Equipment	3,654,195	3,855,042
149	(593) Maintenance of Overhead Lines	55,587,281	41,519,207
150	(594) Maintenance of Underground Lines	8,588,056	9,721,350
151	(595) Maintenance of Line Transformers	1,003,248	1,148,771
152	(596) Maintenance of Street Lighting and Signal Systems	508,056	381,885
153	(597) Maintenance of Meters	1,334,033	1,210,926
154	(598) Maintenance of Miscellaneous Distribution Plant	10,449,290	7,256,561
155	TOTAL Maintenance (Total of lines 146 thru 154)	81,754,435	65,920,153
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	144,172,571	122,067,289
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,833	47,548
160	(902) Meter Reading Expenses	7,039,043	7,076,897
161	(903) Customer Records and Collection Expenses	49,578,656	47,158,258
162	(904) Uncollectible Accounts	32,442,012	37,564,591
163	(905) Miscellaneous Customer Accounts Expenses	3,085,088	4,404,799
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	92,146,632	96,252,093

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	312,867,068	306,274,455
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	385,185	346,151
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	313,252,253	306,620,606
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses	39,030	55,740
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	39,030	55,740
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	84,780,703	82,508,862
182	(921) Office Supplies and Expenses	4,881,672	5,363,749
183	(Less) (922) Administrative Expenses Transferred-Credit	6,653,671	6,191,068
184	(923) Outside Services Employed	35,004,366	37,807,149
185	(924) Property Insurance	1,048,492	1,167,165
186	(925) Injuries and Damages	10,965,412	10,684,251
187	(926) Employee Pensions and Benefits	-6,245,174	21,424,626
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	11,947,392	11,762,078
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	272,376	246,003
192	(930.2) Miscellaneous General Expenses	3,757,305	9,575,774
193	(931) Rents	2,825,890	3,209,438
194	TOTAL Operation (Enter Total of lines 181 thru 193)	142,584,763	177,558,027
195	Maintenance		
196	(935) Maintenance of General Plant	21,231	99,526
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	142,605,994	177,657,553
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,220,450,456	2,012,479,412

Schedule Page: 320 Line No.: 85 Column: b
East total is $1,148,881. These costs are 100% internal costs.

Schedule Page: 320 Line No.: 85 Column: c
East total is $1,166,130. These costs are 100% internal costs.

Schedule Page: 320 Line No.: 86 Column: b
East total is $1,025,018. These costs are 100% internal costs.

Schedule Page: 320 Line No.: 86 Column: c
East total is $1,020,365. These costs are 100% internal costs.

Schedule Page: 320 Line No.: 87 Column: b
East total is $510,333. These costs are 100% internal costs.

Schedule Page: 320 Line No.: 87 Column: c
East total is $505,558. These costs are 100% internal costs.

Schedule Page: 320 Line No.: 88 Column: b
East total is $12,990,162. These costs are 100% external costs.

Schedule Page: 320 Line No.: 88 Column: c
East total is $13,834,851. These costs are 100% external costs.

Schedule Page: 320 Line No.: 89 Column: b
East total is $1,362,037. Internal costs and external costs are $1,091,075 and $270,962, respectively.

Schedule Page: 320 Line No.: 89 Column: c
East total is $1,302,216. Internal costs and external costs are $1,048,426 and $253,790, respectively.

Schedule Page: 320 Line No.: 90 Column: b
East total is $468,520. These costs are 100% internal costs.

Schedule Page: 320 Line No.: 90 Column: c
East total is $510,973. These costs are 100% internal costs.

Schedule Page: 320 Line No.: 92 Column: b
East total is $19,650. These costs are 100% external costs.

Schedule Page: 320 Line No.: 92 Column: c
East total is $17,254. These costs are 100% external costs.

Schedule Page: 320 Line No.: 96 Column: b

East total is $401,237,982.

East Information on Formula Rates Page 106 line 4:
Hydro Quebec DC Phase I Support see page 332 col g ln 6
Hydro Quebec DC Phase II Support see page 332 col g ln 7

Schedule Page: 320 Line No.: 96 Column: c
East total is $393,996,732.

East-Information on Formula Rates Page 106 line 4:
Hydro Quebec DC Phase I Support see page 332 col g ln 5
Hydro Quebec DC Phase II Support see page 332 col g ln 6

Schedule Page: 320 Line No.: 98 Column: b
East total is $47,732.

East - Information on Formula Rates Page 106 line 4:

Schedule Page: 320 Line No.: 98 Column: c
East total is $68,105.

East - Information on Formula Rates Page 106 line 4:

Schedule Page: 320 Line No.: 99 Column: b

Line No.	Account	TOTAL	EAST	WEST TOTAL	WEST DISTRIBUTION	WEST TRANSMISSION
83	560	6,096,851	4,423,477	1,673,374		1,673,374
85	561.1	1,148,881	1,148,881	-		
86	561.2	1,025,018	1,025,018	-		
87	561.3	510,333	510,333	-		
88	561.4	14,257,125	12,990,162	1,266,963	1,266,963	
89	561.5	1,725,304	1,362,037	363,267	46,460	316,807
90	561.6	684,619	468,520	216,099		216,099
92	561.8	19,593	19,650	(57)		(57)
93	562	4,349,658	2,317,792	2,031,866		2,031,866
94	563	2,146,390	1,617,127	529,263		529,263
95	564	4,953,941	4,745,653	208,288		208,288
96	565	414,526,625	401,237,982	13,288,643	12,930,585	358,058
97	566	240,115	108,142	131,973		131,973
98	567	91,574	47,732	43,842		43,842
99	Total	451,776,027	432,022,506	19,753,521	14,244,008	5,509,513

Schedule Page: 320 Line No.: 99 Column: c

Line No.	Account	TOTAL	EAST	WEST
83	560	5,425,056	3,963,330	1,461,726
85	561.1	1,166,148	1,166,130	18
86	561.2	1,020,373	1,020,365	8
87	561.3	505,584	505,558	26
88	561.4	15,142,905	13,834,851	1,308,054
89	561.5	1,701,943	1,302,216	399,727
90	561.6	733,592	510,973	222,619
92	561.8	17,323	17,254	69
93	562	2,949,209	2,057,264	891,945
94	563	534,469	363,025	171,444
95	564	5,078,340	4,740,651	337,689
96	565	405,297,157	393,996,732	11,300,425
97	566	367,240	235,653	131,587
98	567	75,693	68,105	7,588
99	Total	440,015,032	423,782,107	16,232,925

Schedule Page: 320 Line No.: 111 Column: b

Line No.	Account	TOTAL	EAST	WEST TOTAL	WEST DISTRIBUTION	WEST TRANSMISSION

101	568	401,228	168,358	232,870		232,870
102	569.0	558,414	306,488	251,926	730	251,196
103	569.1	315,855	315,855	-		-
104	569.2	616,994	616,994	-		-
107	570	3,129,469	2,740,190	389,279	(1)	389,280
108	571	10,438,202	4,749,564	5,688,638		5,688,638
109	572	(101,422)	(101,449)	27		27
110	573	595	-	595		595
111	Total	15,359,335	8,796,000	6,563,335	729	6,562,606

Schedule Page: 320 Line No.: 111 Column: c

Line No.	Account	TOTAL	EAST	WEST
101	568	416,760	198,945	217,815
102	569.0	406,031	186,469	219,562
103	569.1	519,180	519,180	-
104	569.2	638,095	638,095	-
107	570	1,952,781	1,515,523	437,258
108	571	9,562,414	4,729,379	4,833,035
109	572	8,232,725	8,232,659	66
110	573	317	-	317
111	Total	21,728,303	16,020,250	5,708,053

WEST:
Calculated per company records as stipulated per contract.
Reference Page 106.3 line 23.

Schedule Page: 320 Line No.: 112 Column: b

WEST:
Information on Formula Rates:
Calculated per company records as stipulated per contract.
Page 106.3 line 15 and 23

Schedule Page: 320 Line No.: 121 Column: b

Line No.	Account	TOTAL	EAST	WEST TOTAL	WEST DISTRIBUTION	WEST TRANSMISSION
121	575.7	278,766	236,628	42,138	42,138	-

Schedule Page: 320 Line No.: 121 Column: c

Line No.	Account	TOTAL	EAST	WEST
121	575.7	427,859	388,066	39,793

Schedule Page: 320 Line No.: 184 Column: c

EAST:
NSTAR Electric Company received FERC order ER16-1023 allowing collection of $7,800,000 of merger-related costs over a twelve month period commencing on June 1, 2016. In 2017, $3,250,000 was expensed to account 923 and subject to 100% recovery from transmission customers.

Schedule Page: 320 Line No.: 185 Column: c

WEST:
Note that for the year ended December 31, 2017, the total amount of Property Insurance in Account 924 includes a transmission related component of $134,032.

Schedule Page: 320 Line No.: 187 Column: b

EAST:

Postretirement Benefits Other Than Pension (PBOP)	$(36,897,000)
Capitalized and Other	19,368,000
Recoverable PBOP Expense	$(17,529,000)

Schedule Page: 320 Line No.: 187 Column: c

EAST:

Postretirement Benefits Other Than Pension (PBOP)	$(32,217,000)
Capitalized and Other	18,720,000
Recoverable PBOP Expense	$(13,497,000)

Schedule Page: 320 Line No.: 189 Column: c

WEST:
Note that for the year ended December 31, 2017, the total amount of Regulatory Commission Expenses in Account 928 includes a transmission related component of $373,726.

Schedule Page: 320 Line No.: 191 Column: c

WEST:
Note that for the year ended December 31, 2017, the total amount of General Advertising Expenses in Account 930.1 includes a transmission related component of $7,430.

Schedule Page: 320 Line No.: 196 Column: c

WEST:
Note that for the year ended December 31, 2017, the total amount of Administrative and General Expenses in Account 920 through 935 includes a transmission related component of $12,577,615 which includes a transmission merger amortization expense of $1,458,331.

Schedule Page: 320 Line No.: 197 Column: b

Line No.	Account	TOTAL	EAST	WEST TOTAL	WEST DISTRIBUTION	WEST TRANSMISSION
181	920	84,780,703	66,474,318	18,306,385	11,244,272	7,062,113
182	921	4,881,672	3,793,909	1,087,763	756,996	330,767
183	922	(6,653,671)	(5,685,942)	(967,729)	(613,021)	(354,708)
184	923	35,004,366	27,914,652	7,089,714	4,377,385	2,712,329
185	924	1,048,492	827,708	220,784	93,625	127,159
186	925	10,965,412	8,078,783	2,886,629	2,582,180	304,449
187	926	(6,245,174)	(6,816,665)	571,491	219,398	352,093
189	928	11,947,392	10,139,928	1,807,464	1,424,845	382,619
191	930.1	272,376	207,274	65,102	63,629	1,473
192	930.2	3,757,305	2,977,036	780,269	486,589	293,680

193	931	2,825,890	2,307,717	518,173	171,405	346,768
196	935	21,231	1,149	20,082	13,074	7,008
197	Total	142,605,994	110,219,867	32,386,127	20,820,377	11,565,750

Schedule Page: 320 Line No.: 197 Column: c

Line No.	Account	TOTAL	EAST	WEST
181	920	82,508,862	63,602,187	18,906,675
182	921	5,363,749	4,111,268	1,252,481
183	922	(6,191,068)	(5,253,075)	(937,993)
184	923	37,807,149	29,671,648	8,135,501
185	924	1,167,165	930,834	236,331
186	925	10,684,251	9,010,252	1,673,999
187	926	21,424,626	19,640,559	1,784,067
189	928	11,762,078	10,011,774	1,750,304
191	930.1	246,003	158,361	87,642
192	930.2	9,575,774	7,491,466	2,084,308
193	931	3,209,438	2,681,689	527,749
196	935	99,526	-	99,526
197	Total	177,657,553	142,056,963	35,600,590

WEST:
Note that for the year ended December 31, 2017, the total amount of Administrative and General Expenses in Account 920 through 935 includes a transmission related component of $12,577,615 which includes a transmission merger amortization expense of $1,458,331.

Schedule Page: 320 Line No.: 198 Column: b

EAST:
-Information on Formula Rates: Page 106.2 line 1:
Amount as stipulated per contract.

Schedule Page: 320 Line No.: 198 Column: c

EAST-Information on Formula Rates Page 106.2 line 1:
Amount as stipulated per contract.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	EAST					
2						
3	Nonassociated Utilities/Companies:					
4	Competitive Suppliers	OS				
5	Enel Green Power North America, Inc.	LU		7.8	16.3	
6	Massachusetts Bay	LU		14.3	14.7	
7	Vermont Yankee Nuclear Power Corp.	LU	12			
8	Atlantic Renewables Project, LLC	LU	1			
9	Atlantic Renewables Project, LLC	OS				
10	Blue Sky East, LLC	LU	1			
11	Blue Sky East, LLC	OS				
12	Blue Sky West Holdings, LLC	LU	1			
13	Blue Sky West Holdings, LLC	OS				
14	Direct Energy Business Marketing, LLC	SF	1			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	DTE Energy Trading, Inc.	SF	1			
2	Emera Energy Services, Inc.	SF	1			
3	Evergreen Wind Power II, LLC	LU	1			
4	Evergreen Wind Power II, LLC	OS				
5	Exelon Generation Corp, LLC	SF	11			
6	Groton Wind, LLC	LU	1			
7	Groton Wind, LLC	OS				
8	National Grid	OS				
9	New England Wind, LLC	LU	1			
10	New England Wind, LLC	OS				
11	NextEra Energy Power Marketing, LTD	SF	1			
12	TransCanada Power Marketing, LTD	SF	1			
13	TransCanada Maine Wind, LLC	LU	1			
14	TransCanada Maine Wind, LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Vitol, Inc.	SF	1			
2						
3	Municipals:					
4	Middleborough Gas and Electric Depart.	OS				
5	Reading Municipal Light Department	OS				
6						
7	Other Sellers:					
8	Basic Service Deferral	OS				
9	Basic Service Deferral	AD				
10	MA Renewable Portfolio Standards	OS				
11	Net Metering Deferral	OS				
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	WEST					
2						
3	Associated Utilities:					
4	Connecticut Light & Power Company	OS				
5	Connecticut Yankee Atomic Power Co.	LU	CYAPC1			
6	Maine Yankee Atomic Power Company	LU	MYACP1			
7	Yankee Atomic Electric Company	LU	YAEC1			
8						
9	Nonassociated Utilities/Companies:					
10	Blue Sky West Holdings LLC	LU				
11	Competitive Suppliers	OS				
12	Direct Energy Business Marketing, LLC	OS				
13	DTE Energy Trading, Inc.	OS				
14	Evergreen Wind Power II, LLC	LU				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Exelon Generation Company, LLC	OS				
2	Green Mountain Power	OS				
3	ISO New England	OS	ISO-NE			
4	National Grid	OS				
5	NextEra Energy Power Marketing, LLC	OS				
6	Noble Passadumkeag Windpark, LLC	LU				
7	TransCanada Power Marketing. LtTD	OS				
8	Vermont Yankee Nuclear Power Corp.	LU	VYNPC 12			
9						
10	Municipals:					
11	Pittsfield, City of	OS				
12	Pittsfield, City of	AD				
13	Town of Lee Board of Public Works	OS				
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Other Sellers:					
2	Basic Service Deferral	OS				
3	Basic Service Deferral	AD				
4	Long-Term Renewable Contract Deferrals	OS				
5	Long-Term Renewable Contract Deferrals	AD				
6	MA Renewable Portfolio Standards	OS				
7	MA Renewable Portfolio Standards	AD				
8	Net Metering Deferral	OS				
9	Residential, Commercial, Industrial					
10	and Other Nonutility Generators	OS				
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
							2
							3
15,762,796							4
95,420				8,587,773		8,587,773	5
			1,891,086		-1,200,000	691,086	6
					35,731	35,731	7
52,616				2,870,321		2,870,321	8
				1,358,570		1,358,570	9
102,538				7,259,341		7,259,341	10
				902,326		902,326	11
228,285				14,119,452		14,119,452	12
				3,670,616		3,670,616	13
80,964				7,437,053		7,437,053	14
26,630,065			1,891,086	933,685,464	123,953,609	1,059,530,159	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
113,230				9,867,881		9,867,881	1
560				35,264		35,264	2
161,451				9,525,589		9,525,589	3
				2,728,581		2,728,581	4
693,370				67,560,120		67,560,120	5
107,080				5,530,708		5,530,708	6
				3,344,790		3,344,790	7
2,796				486,468		486,468	8
77,895				4,880,116		4,880,116	9
				2,347,710		2,347,710	10
4,569,966				405,990,016		405,990,016	11
-8,330				-661,843		-661,843	12
64,552				4,200,590		4,200,590	13
				2,550,856		2,550,856	14
26,630,065			1,891,086	933,685,464	123,953,609	1,059,530,159	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
23,453				2,071,128		2,071,128	1
							2
							3
223				34,089		34,089	4
3,085				474,764		474,764	5
							6
							7
					125,468,672	125,468,672	8
					-463,964	-463,964	9
				110,133,058		110,133,058	10
478,560				89,007,329		89,007,329	11
							12
							13
							14
26,630,065			1,891,086	933,685,464	123,953,609	1,059,530,159	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
							2
							3
42				3,782	4,786	8,568	4
					15,199	15,199	5
					21,367	21,367	6
					15,073	15,073	7
							8
							9
38,621				3,074,093		3,074,093	10
2,138,149							11
454,646				35,901,943		35,901,943	12
-2,354				-166,084		-166,084	13
27,191				2,063,716		2,063,716	14
26,630,065			1,891,086	933,685,464	123,953,609	1,059,530,159	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
454,786				34,636,089		34,636,089	1
56				8,302	1,914	10,216	2
				-4	209	205	3
279				29,473	23,635	53,108	4
470,260				34,817,452		34,817,452	5
143,003				10,810,560		10,810,560	6
3,247				219,358		219,358	7
					30,987	30,987	8
							9
							10
143				6,451		6,451	11
1				180		180	12
2				42		42	13
							14
26,630,065			1,891,086	933,685,464	123,953,609	1,059,530,159	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
				-150,797		-150,797	2
				718,678		718,678	3
				3,114,093		3,114,093	4
				-490,457		-490,457	5
				28,278,528		28,278,528	6
				-503,376		-503,376	7
127,448				-4,422,965		-4,422,965	8
							9
164,035				19,423,741		19,423,741	10
							11
							12
							13
							14
26,630,065			1,891,086	933,685,464	123,953,609	1,059,530,159	

FOOTNOTE DATA

Schedule Page: 326 Line No.: 4 Column: b

Represents energy for those customers who have chosen third party suppliers. NSTAR Electric Company (East) delivers energy to these customers, but does not bear the supply costs.

Schedule Page: 326 Line No.: 5 Column: b

Boston Edison Company - Boott Mills Hydro contract.

Schedule Page: 326 Line No.: 6 Column: b

Boston Edison Company - MBTA Jet 2 contract.

Schedule Page: 326 Line No.: 9 Column: b

Short-term REC purchases.

Schedule Page: 326 Line No.: 11 Column: b

Short-term REC purchases.

Schedule Page: 326 Line No.: 13 Column: b

Short-term REC purchases.

Schedule Page: 326.1 Line No.: 4 Column: b

Short-term REC purchases.

Schedule Page: 326.1 Line No.: 7 Column: b

Short-term REC purchases.

Schedule Page: 326.1 Line No.: 8 Column: b

Borderline Service.

Schedule Page: 326.1 Line No.: 10 Column: b

Short-term REC purchases.

Schedule Page: 326.1 Line No.: 14 Column: b

Short-term REC purchases.

Schedule Page: 326.2 Line No.: 4 Column: b

Borderline Service.

Schedule Page: 326.2 Line No.: 5 Column: b

Borderline Service.

Schedule Page: 326.2 Line No.: 8 Column: b

Cumulative recovery of Basic Service costs of 2018.

Schedule Page: 326.2 Line No.: 9 Column: b

Prior years' adjustment for Recovery of Basic Service.

Schedule Page: 326.2 Line No.: 10 Column: b

Accrual for the anticipated yearly expense associated with the cost of energy procurement in compliance with the Massachusetts Renewable Portfolio Standards.

Schedule Page: 326.2 Line No.: 11 Column: b

Cumulative recovery of net metering deferral costs for 2018.

Schedule Page: 326.3 Line No.: 4 Column: b

Borderline Service.

Schedule Page: 326.3 Line No.: 5 Column: c

Connecticut Yankee Atomic Power Company rate schedule number.

Schedule Page: 326.3 Line No.: 6 Column: c

Maine Yankee Atomic Power Company rate schedule number.

Schedule Page: 326.3 Line No.: 7 Column: c

Yankee Atomic Electric Company rate schedule number.

Schedule Page: 326.3 Line No.: 11 Column: b

Represents energy for those customers who have chosen third party suppliers. NSTAR Electric Company (West) delivers energy to these customers, but does not bear the supply costs.

Schedule Page: 326.3 Line No.: 12 Column: b

Basic Service.

Schedule Page: 326.3 Line No.: 13 Column: b

Basic Service.

Schedule Page: 326.4 Line No.: 1 Column: b

Basic Service.

Schedule Page: 326.4 Line No.: 2 Column: b

Borderline Service.

Schedule Page: 326.4 Line No.: 3 Column: b

Short-term energy and capacity purchases.

Schedule Page: 326.4 Line No.: 3 Column: c

ISO New England, Inc. Transmission, Markets and Services Tariff.

Schedule Page: 326.4 Line No.: 4 Column: b

Borderline Service.

Schedule Page: 326.4 Line No.: 5 Column: b

Basic Service.

Schedule Page: 326.4 Line No.: 7 Column: b

Basic Service.

Schedule Page: 326.4 Line No.: 8 Column: c

Vermont Yankee Nuclear Power Corporation rate schedule number.

Schedule Page: 326.4 Line No.: 11 Column: b

Non-firm purchase power from Municipal Generator.

Schedule Page: 326.4 Line No.: 12 Column: b

Prior period adjustment of non-firm purchase power from Municipal Generator.

Schedule Page: 326.4 Line No.: 13 Column: b

Non-firm purchase power from Municipal Generator.

Schedule Page: 326.5 Line No.: 2 Column: b

Cumulative recovery of Basic Service costs for 2018.

Schedule Page: 326.5 Line No.: 3 Column: b

Prior years' adjustment for recovery of Basic Service.

Schedule Page: 326.5 Line No.: 4 Column: b

Cumulative recovery of Long-Term Renewable Contract Deferrals costs for 2018.

Schedule Page: 326.5 Line No.: 5 Column: b

Prior years' adjustment for Long-Term Renewable Contract Deferrals.

Schedule Page: 326.5 Line No.: 6 Column: b

Accrual for the anticipated yearly expense associated with the cost of energy procurement in compliance with the Massachusetts Renewable Portfolio Standards.

Schedule Page: 326.5 Line No.: 7 Column: b

Prior period adjustment for accrual for the anticipated yearly expense associated with the cost of energy procurement in compliance with the Massachusetts Renewable Portfolio Standards.

Schedule Page: 326.5 Line No.: 8 Column: b

Cumulative recovery of net metering deferral costs for 2018.

Schedule Page: 326.5 Line No.: 10 Column: b

This represents Residential and Commercial Nonutility Generators who generate energy and is recorded as Non-firm purchase power.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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 Classification (d)
1	NSTAR ELECTRIC COMPANY (EAST)			
2	FIRM WHEELING SERVICE			
3	Covanta Energy	Various	Covanta Energy	AD
4	Dartmouth Power Associates Limited	Dartmouth Power Associates Ltd.	ISO-NE	LFP
5	HQ Energy Services, U.S.	HQ Energy Services, US	HQ Phase I or II	OLF
6	HQ Energy Services, U.S.	HQ Energy Services, US	HQ Phase I or II	AD
7	HQ Energy Services, U.S.	HQ Energy Services, US	HQ Phase I or II	AD
8				
9	NON FIRM WHEELING SERVICE			
10	HQ Energy Services, U.S.	HQ Energy Services, US	HQ Phase I or II	NF
11	HQ Energy Services, U.S.	HQ Energy Services, US	HQ Phase I or II	AD
12	HQ Energy Services, U.S.	HQ Energy Services, US	HQ Phase I or II	AD
13				
14	NEPOOL/ISO			
15	OATT- RNS Transmission Revenue	N/A	N/A	OS
16	OATT - Scheduling & Dispatch Service	N/A	N/A	OS
17	OATT - Through or Out Service	N/A	N/A	OS
18				
19	OTHER SERVICE			
20	Belmont Municipal Light	Various	Belmont Municipal Light	AD
21	Hydro Quebec Phase II Support	Various	Various	OS
22	Hydro Quebec Phase II Support	Various	Various	AD
23	Hydro Quebec Phase II Support	Associated Utility	Various	OS
24	Hydro Quebec Phase II Support	Associated Utility	Various	AD
25	New England Power Lines 255-2337/2338	Various	Various	OS
26	New England Power Lines 255-2337/2338	Various	Various	AD
27	Concord Municipal Light-Wellesley	Various	Various	OS
28	Concord Municipal Light-Wellesley	Various	Various	AD
29	National Grid-Dewar Street	Various	Various	OS
30	National Grid-Dewar Street	Various	Various	AD
31	ANP Blackstone Energy Co.	Various	Various	OS
32	ANP Blackstone Energy Co.	Various	Various	AD
33	Granite Ridge Energy, LLC	Various	Various	OS
34	Granite Ridge Energy, LLC	Various	Various	AD
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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 Classification (d)
1	New England Power-Merchants Way	Various	Various	OS
2	New England Power-Merchants Way	Various	Various	AD
3	Millennium Power Partners, L.P.	Various	Various	OS
4	Millennium Power Partners, L.P.	Various	Various	AD
5	Constellation Mystic Power, LLC	Various	Various	OS
6	Calpine Fore River Energy Center, LLC	Various	Various	OS
7	Calpine Fore River Energy Center, LLC	Various	Various	AD
8	Gen On Kendall, LLC	Kendall Station	Various	OS
9	Gen On Kendall, LLC	Kendall Station	Various	AD
10	Entergy Nuclear Generation Co.	Various	Entergy Nuclear Generation Co.	OS
11	Entergy Nuclear Generation Co.	Various	Entergy Nuclear Generation Co.	AD
12	National Grid-Edgar Station	Various	Various	OS
13	Nalcor Energy Marketing Corporation	N/A	N/A	OS
14				
15	NETWORK SERVICE			
16	Massachusetts Bay Transportation Authority	Various	Massachusetts Bay Transportation	FNO
17	Massachusetts Bay Transportation Authority	Various	Massachusetts Bay Transportation	AD
18	Concord Municipal Light-LNS	Various	Concord Municipal Light	FNO
19	Concord Municipal Light-LNS	Various	Concord Municipal Light	AD
20	Massachusetts Port Authority	Various	Massachusetts Port Authority	FNO
21	Massachusetts Port Authority	Various	Massachusetts Port Authority	AD
22	National Grid-Nantucket Cable	Various	National Grid	FNO
23	National Grid-Nantucket Cable	Various	National Grid	AD
24	NSTAR Electric Company (East)	Associated Utility	NSTAR Electric Company (East)	FNS
25				
26				
27				
28	NSTAR ELECTRIC COMPANY (WEST)			
29	FIRM WHEELING SERVICE			
30	Essential Power Massachusetts, LLC	Essential Power Massachusetts,LLC	Various	LFP
31	HQ Energy Services, U.S.	HQ Energy Services, U.S.	HQ Phase I or II	OLF
32	NRG Energy, Inc.	NRG Energy, Inc.	NEPOOL PTF	LFP
33				
34	NON-FIRM WHEELING SERVICE			
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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 Classification (d)
1	Algonquin Windsor Locks, LLC	Algonquin Windsor Locks, LLC	NEPOOL PTF	NF
2	Algonquin Windsor Locks, LLC	Algonquin Windsor Locks, LLC	NEPOOL PTF	AD
3	Brookfield Energy Marketing LP - Berlin	Brookfield Energy Marketing LP	NEPOOL PTF	NF
4	Brookfield Energy Marketing LP - Berlin	Brookfield Energy Marketing LP	NEPOOL PTF	AD
5	Brookfield Energy Marketing LP - Pontook	Brookfield Energy Marketing LP	NEPOOL PTF	NF
6	Brookfield Energy Marketing LP - Pontook	Brookfield Energy Marketing LP	NEPOOL PTF	AD
7	Brookfield Energy Marketing LP-HQ	Brookfield Energy Marketing LP-HQ	HQ Phase I or II	NF
8	Covanta Energy Marketing, LLC	Covanta Energy Marketing, LLC	NEPOOL PTF	NF
9	Covanta Energy Marketing, LLC	Covanta Energy Marketing, LLC	NEPOOL PTF	AD
10	Covanta Springfield, LLC	Covanta Springfield, LLC	NEPOOL PTF	NF
11	Covanta Springfield, LLC	Covanta Springfield, LLC	NEPOOL PTF	AD
12	Essential Power Massachusetts, LLC	Essential Power Massachusetts,LLC	NEPOOL PTF	NF
13	Essential Power Massachusetts, LLC	Essential Power Massachusetts,LLC	NEPOOL PTF	AD
14	FirstLight Power Resources, Inc.	FirstLight Power Resources, Inc	NEPOOL PTF	NF
15	FirstLight Power Resources, Inc.	FirstLight Power Resources, Inc.	NEPOOL PTF	AD
16	FirstLight Power Resources Management	FirstLight Power Resources	NEPOOL PTF	NF
17	FirstLight Power Resources Management	FirstLight Power Resources	NEPOOL PTF	AD
18	Granite Reliable Power, LLC	Granite Reliable Power, LLC	NEPOOL PTF	NF
19	Granite Reliable Power, LLC	Granite Reliable Power, LLC	NEPOOL PTF	AD
20	GSP Newington, LLC	GSP Newington, LLC	NEPOOL PTF	NF
21	GSP Lost Nation, LLC	GSP Lost Nation, LLC	NEPOOL PTF	NF
22	HSE Hydro NH Canaan, LLC	HSE Hydro NH Canaan, LLC	NEPOOL PTF	NF
23	HSE Hydro NH Gorham, LLC	HSE Hydro NH Gorham, LLC	NEPOOL PTF	NF
24	HSE Hyrdro NH Smith, LLC	HSE Hyrdro NH Smith, LLC	NEPOOL PTF	NF
25	Jericho Power, LLC	Jericho Power, LLC	NEPOOL PTF	NF
26	Jericho Power, LLC	Jericho Power, LLC	NEPOOL PTF	AD
27	Messalonskee Stream Hydro, LLC	Messalonskee Stream Hydro, LLC	NEPOOL PTF	NF
28	Messalonskee Stream Hydro, LLC	Messalonskee Stream Hydro, LLC	NEPOOL PTF	AD
29	Pittsfield Generating Company, LP	Pittsfield Generating Company, LP	NEPOOL PTF	NF
30	Pittsfield Generating Company, LP	Pittsfield Generating Company, LP	NEPOOL PTF	AD
31	Plainfield Renewable Energy, LLC	Plainfield Renewable Energy, LLC	NEPOOL PTF	NF
32	Plainfield Renewable Energy, LLC	Plainfield Renewable Energy, LLC	NEPOOL PTF	AD
33	Power Supply Services, LLC	Power Supply Services, LLC	NEPOOL PTF	NF
34	Power Supply Services, LLC	Power Supply Services, LLC	NEPOOL PTF	AD
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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 Classification (d)
1	The Springfield Water and Sewer	The Springfield Water and Sewer	NEPOOL PTF	NF
2	The Springfield Water and Sewer	The Springfield Water and Sewer	NEPOOL PTF	AD
3	Sterling Light Department	Sterling Light Department	NEPOOL PTF	NF
4	Sterling Light Department	Sterling Light Department	NEPOOL PTF	AD
5	Sterling Municipal Light Department	Sterling Municipal Light Depart	NEPOOL PTF	NF
6	Sterling Municipal Light Department	Sterling Municipal Light Depart	NEPOOL PTF	AD
7	Waterbury Generation, LLC	Waterbury Generation, LLC	NEPOOL PTF	NF
8	Waterbury Generation, LLC	Waterbury Generation, LLC	NEPOOL PTF	AD
9	Woods Hill Solar, LLC	Woods Hill Solar, LLC	NEPOOL PTF	NF
10				
11	TRANSMISSION SUPPORT			
12	Massachusetts Municipal Wholesale Elec.	Not Applicable	Not Applicable	OS
13				
14	NEPOOL/ISO			
15	OATT - Regional Network Service	Not Applicable	Not Applicable	OS
16	OATT - Scheduling & Dispatch Service	Not Applicable	Not Applicable	OS
17	OATT - Through or Out Service	Not Applicable	Not Applicable	OS
18				
19	OTHER SERVICE			
20	Shared Microwave Transmission Revenue	Not Applicable	Not Applicable	OS
21	Ashburnham Municipal Light Department	Not Applicable	Not Applicable	OS
22	Ashburnham Municipal Light Department	Not Applicable	Not Applicable	AD
23	Belmont Municipal Light Department	Not Applicable	Not Applicable	OS
24	Belmont Municipal Light Department	Not Applicable	Not Applicable	AD
25	Boylston Municipal Light Department	Not Applicable	Not Applicable	OS
26	Braintree Electric Light Department	Not Applicable	Not Applicable	OS
27	Braintree Electric Light Department	Not Applicable	Not Applicable	AD
28	Chicopee Municipal Lighting Plant	Not Applicable	Not Applicable	OS
29	Chicopee Municipal Lighting Plant	Not Applicable	Not Applicable	AD
30	Concord Municipal Light Plant	Not Applicable	Not Applicable	OS
31	Concord Municipal Light Plant	Not Applicable	Not Applicable	AD
32	Danvers Electric Division	Not Applicable	Not Applicable	OS
33	Danvers Electric Division	Not Applicable	Not Applicable	AD
34	Fitchburg Gas and Electric Light	Not Applicable	Not Applicable	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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 Classification (d)
1	Fitchburg Gas and Electric Light	Not Applicable	Not Applicable	AD
2	Georgetown Municipal Light Department	Not Applicable	Not Applicable	OS
3	Georgetown Municipal Light Department	Not Applicable	Not Applicable	AD
4	Groton Electric Light Department	Not Applicable	Not Applicable	OS
5	Groton Electric Light Department	Not Applicable	Not Applicable	AD
6	Groveland Electric Light Department	Not Applicable	Not Applicable	OS
7	Groveland Electric Light Department	Not Applicable	Not Applicable	AD
8	Hingham Municipal Lighting Plant	Not Applicable	Not Applicable	OS
9	Hingham Municipal Lighting Plant	Not Applicable	Not Applicable	AD
10	Holden Municipal Light Department	Not Applicable	Not Applicable	OS
11	Holden Municipal Light Department	Not Applicable	Not Applicable	AD
12	Holyoke Gas & Electric Department	Not Applicable	Not Applicable	OS
13	Holyoke Gas & Electric Department	Not Applicable	Not Applicable	AD
14	Hudson Light & Power Department	Not Applicable	Not Applicable	OS
15	Hudson Light & Power Department	Not Applicable	Not Applicable	AD
16	Hull Municipal Lighting Plant	Not Applicable	Not Applicable	OS
17	Hull Municipal Lighting Plant	Not Applicable	Not Applicable	AD
18	Ipswich Municipal Light Department	Not Applicable	Not Applicable	OS
19	Ipswich Municipal Light Department	Not Applicable	Not Applicable	AD
20	Littleton Electric Light & Water	Not Applicable	Not Applicable	OS
21	Littleton Electric Light & Water	Not Applicable	Not Applicable	AD
22	Mansfield Municipal Electric Light	Not Applicable	Not Applicable	OS
23	Mansfield Municipal Electric Light	Not Applicable	Not Applicable	AD
24	Marblehead Municipal Light Department	Not Applicable	Not Applicable	OS
25	Marblehead Municipal Light Department	Not Applicable	Not Applicable	AD
26	Massachusetts Bay Transportation Authority	Not Applicable	Not Applicable	OS
27	Massachusetts Bay Transportation Authority	Not Applicable	Not Applicable	AD
28	Massachusetts Development Finance Agency	Not Applicable	Not Applicable	OS
29	Massachusetts Development Finance Agency	Not Applicable	Not Applicable	AD
30	Massachusetts Electric Company	Not Applicable	Not Applicable	OS
31	Massachusetts Electric Company	Not Applicable	Not Applicable	AD
32	Massachusetts Port Authority	Not Applicable	Not Applicable	OS
33	Massachusetts Port Authority	Not Applicable	Not Applicable	AD
34	MATEP, LLC	Not Applicable	Not Applicable	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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 Classification (d)
1	MATEP, LLC	Not Applicable	Not Applicable	AD
2	Merrimac Municipal Light Plant	Not Applicable	Not Applicable	OS
3	Middleborough Gas & Electric Division	Not Applicable	Not Applicable	OS
4	Middleborough Gas & Electric Division	Not Applicable	Not Applicable	AD
5	Middleton Municipal Light Department	Not Applicable	Not Applicable	OS
6	Middleton Municipal Light Department	Not Applicable	Not Applicable	AD
7	New England Power Company	Not Applicable	Not Applicable	OS
8	New England Power Company	Not Applicable	Not Applicable	AD
9	North Attleborough Electric Department	Not Applicable	Not Applicable	OS
10	North Attleborough Electric Department	Not Applicable	Not Applicable	AD
11	Norwood Municipal Light Department	Not Applicable	Not Applicable	OS
12	Norwood Municipal Light Department	Not Applicable	Not Applicable	AD
13	Paxton Municipal Light Department	Not Applicable	Not Applicable	OS
14	Paxton Municipal Light Department	Not Applicable	Not Applicable	AD
15	Peabody Municipal Light Plant	Not Applicable	Not Applicable	OS
16	Peabody Municipal Light Plant	Not Applicable	Not Applicable	AD
17	Princeton Municipal Light Department	Not Applicable	Not Applicable	OS
18	Reading Municipal Light Department	Not Applicable	Not Applicable	OS
19	Reading Municipal Light Department	Not Applicable	Not Applicable	AD
20	Rowley Municipal Lighting Plant	Not Applicable	Not Applicable	OS
21	Rowley Municipal Lighting Plant	Not Applicable	Not Applicable	AD
22	Russell Municipal Light Department	Not Applicable	Not Applicable	OS
23	Russell Municipal Light Department	Not Applicable	Not Applicable	AD
24	Shrewsbury Electric Light Plant	Not Applicable	Not Applicable	OS
25	Shrewsbury Electric Light Plant	Not Applicable	Not Applicable	AD
26	South Hadley Electric Light Department	Not Applicable	Not Applicable	OS
27	South Hadley Electric Light Department	Not Applicable	Not Applicable	AD
28	Sterling Municipal Electric Light	Not Applicable	Not Applicable	OS
29	Sterling Municipal Electric Light	Not Applicable	Not Applicable	AD
30	Taunton Municipal Lighting Plant	Not Applicable	Not Applicable	OS
31	Taunton Municipal Lighting Plant	Not Applicable	Not Applicable	AD
32	Templeton Municipal Lighting Plant	Not Applicable	Not Applicable	OS
33	Templeton Municipal Lighting Plant	Not Applicable	Not Applicable	AD
34	Wakefield Municipal Gas & Light	Not Applicable	Not Applicable	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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 Classification (d)
1	Wakefield Municipal Gas & Light	Not Applicable	Not Applicable	AD
2	Wellesley Municipal Light Plant	Not Applicable	Not Applicable	OS
3	Wellesley Municipal Light Plant	Not Applicable	Not Applicable	AD
4	West Boylston Municipal Lighting Plant	Not Applicable	Not Applicable	OS
5	West Boylston Municipal Lighting Plant	Not Applicable	Not Applicable	AD
6	Westfield Gas & Electric Light Department	Not Applicable	Not Applicable	OS
7	Westfield Gas & Electric Light Department	Not Applicable	Not Applicable	AD
8	Chester Municipal Electric Light Department	Not Applicable	Not Applicable	OS
9	Chester Municipal Electric Light Department	Not Applicable	Not Applicable	AD
10				
11	NETWORK SERVICE			
12	Ashland Municipal Electric Department	Various	Ashland Municipal Electric Dept.	FNO
13	Ashland Municipal Electric Department	Various	Ashland Municipal Electric Dept.	AD
14	The Connecticut Light & Power Company	Associated Utility	The Connecticut Light & Power Co.	FNO
15	The Connecticut Light & Power Company	Associated Utility	The Connecticut Light & Power Co.	AD
16	CT Transmission Municipal Electric Energy	Various New England Utilities	CT Transmission Municipal Elec	FNO
17	CT Transmission Municipal Electric Energy	Various New England Utilities	CT Transmission Municipal Elec	AD
18	GenConn Energy, LLC	Various	GenConn Energy, LLC	FNO
19	GenConn Energy, LLC	Various	GenConn Energy, LLC	AD
20	New England Power Company	New England Power	New England Power Company	FNO
21	New England Power Company	New England Power	New England Power Company	AD
22	New Hampshire Electric Co-op.	Various New England Utilities	New Hampshire Electric Co-op.	FNO
23	New Hampshire Electric Co-op.	Various New England Utilities	New Hampshire Electric Co-op.	AD
24	Public Service Company of New Hampshire	Associated Utility	Public Service Company of NH	FNO
25	Public Service Company of New Hampshire	Associated Utility	Public Service Company of NH	AD
26	Unitil Energy Systems, Inc.	Various	Unitil Energy Systems, Inc.	FNO
27	Unitil Energy Systems, Inc.	Various	Unitil Energy Systems, Inc.	AD
28	Waterbury Generation, LLC	Waterbury Generation, LLC	Waterbury Generation, LLC	FNO
29	Waterbury Generation, LLC	Waterbury Generation, LLC	Waterbury Generation, LLC	AD
30	NSTAR Electric Company (West)	Associated Utility	NSTAR Electric Company (West)	FNS
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
						1
						2
ISO-NE OATT	Station 718	Covanta				3
Negotiated	NSTAR LINE 111	High Hill Substation		66,857	66,857	4
ISO-NE OATT	NE HVDC Border	HQ Phase I or II		1,521,202	1,521,202	5
ISO-NE OATT	NE HVDC Border	HQ Phase I or II				6
ISO-NE-OATT	NE HVDC Border	HQ Phase I or II				7
						8
						9
ISO-NE OATT	NE HVDC Border	HQ Phase I or II		308,281	308,281	10
ISO-NE OATT	NE HVDC Border	HQ Phase I or II				11
ISO-NE OATT	NE HVDC Border	HQ Phase I or II				12
						13
						14
ISO-NE OATT	N/A	N/A				15
ISO-NE OATT	N/A	N/A				16
ISO-NE OATT	N/A	N/A				17
						18
						19
36	Station 509	NSTAR System				20
Support	Various	Various				21
Support	Various	Various				22
Support	Various	Various				23
Support	Various	Various				24
Support	Various	Various				25
Support	Various	Various				26
Support	Various	Concord/Wellesley				27
Support	Various	Concord/Wellesley				28
Support	Various	Various				29
Support	Various	Various				30
Tariff Vol. 3-IA	N/A	N/A				31
Tariff Vol. 3-IA	N/A	N/A				32
Tariff Vol. 3-IA	N/A	N/A				33
Tariff Vol. 3-IA	N/A	N/A				34
			0	**28,794,602**	**28,794,602**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
Tariff Vol. 3-IA	N/A	N/A				1
Tariff Vol. 3-IA	N/A	N/A				2
Tariff Vol. 3-IA	N/A	N/A				3
Tariff Vol. 3-IA	N/A	N/A				4
Tariff Vol. 3-IA	N/A	N/A				5
Tariff Vol. 3-IA	N/A	N/A				6
Tariff Vol. 3-IA	N/A	N/A				7
Tariff Vol. 3-IA	Kendall Station	Various				8
Tariff Vol. 3-IA	Kendall Station	Various				9
Tariff Vol. 3-IA	Manomet Station	Pole #178				10
Tariff Vol. 3-IA	Manomet Station	Pole #178				11
Tariff Vol. 3-IA	N/A	N/A				12
Negotiated	N/A	N/A				13
						14
						15
ISO-NE OATT	Various	MBTA		347,635	347,635	16
ISO-NE OATT	Various	MBTA				17
ISO-NE OATT	Various	Concord		167,775	167,775	18
ISO-NE OATT	Various	Concord				19
ISO-NE OATT	Various	MASSPORT		208,255	208,255	20
ISO-NE OATT	Various	MASSPORT				21
ISO-NE OATT	Commonwealth	Lothrop Station		188,566	188,566	22
ISO-NE OATT	Commonwealth	Lothrop Station				23
ISO-NE OATT	Various	NSTAR East System		21,142,456	21,142,456	24
						25
						26
						27
						28
						29
ISO-NE OATT	Various	EVERSOURCE PTF		16,263	16,263	30
ISO-NE OATT	NE HVDC Border	HQ Phase I or II		501,331	501,331	31
ISO-NE OATT	Middletown 345 KV	NEPOOL PTF				32
						33
						34
			0	**28,794,602**	**28,794,602**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
ISO-NE OATT	Windsor Locks Sub	NEPOOL PTF				1
ISO-NE OATT	Windsor Locks Sub	NEPOOL PTF				2
ISO-NE OATT	Berlin Substation	NEPOOL PTF				3
ISO-NE OATT	Berlin Substation	NEPOOL PTF				4
ISO-NE OATT	Pontook Substation	NEPOOL PTF				5
ISO-NE OATT	Pontook Substation	NEPOOL PTF				6
ISO-NE OATT	NE HVDC Border	HQ Phase I or II		30	30	7
ISO-NE OATT	Hallville Substation	NEPOOL PTF				8
ISO-NE OATT	Hallville Substation	NEPOOL PTF				9
ISO-NE OATT	West Springfield Sub	NEPOOL PTF		39,327	39,327	10
ISO-NE OATT	West Springfield Sub	NEPOOL PTF				11
ISO-NE OATT	West Springfield Sub	NEPOOL PTF		3,050	3,050	12
ISO-NE OATT	West Springfield Sub	NEPOOL PTF				13
ISO-NE OATT	Various	NEPOOL PTF				14
ISO-NE OATT	Various	NEPOOL PTF				15
ISO-NE OATT	French King Sub	NEPOOL PTF		1,724	1,724	16
ISO-NE OATT	French King Sub	NEPOOL PTF				17
ISO-NE OATT	Paris Substation	NEPOOL PTF				18
ISO-NE OATT	Paris Substation	NEPOOL PTF				19
ISO-NE OATT	POCO on 115 KV lines	NEPOOL PTF				20
ISO-NE OATT	Lost Nation Subst	NEPOOL PTF				21
ISO-NE OATT	POCO on 34.5kV line	NEPOOL PTF				22
ISO-NE OATT	POCO on 34.5kV line	NEPOOL PTF				23
ISO-NE OATT	POCO on 115KV lines	NEPOOL PTF				24
ISO-NE OATT	Berlin Substation	NEPOOL PTF				25
ISO-NE OATT	Berlin Substation	NEPOOL PTF				26
ISO-NE-OATT	Long Hill SS	NEPOOL PTF				27
ISO-NE-OATT	Long Hill SS	NEPOOL PTF				28
ISO-NE OATT	Pittsfield Sub	NEPOOL PTF		117,976	117,976	29
ISO-NE OATT	Pittsfield Sub	NEPOOL PTF				30
ISO-NE OATT	Fry Brook Substation	NEPOOL PTF				31
ISO-NE OATT	Fry Brook Substation	NEPOOL PTF				32
ISO-NE OATT	Laconia & Longhill	NEPOOL PTF				33
ISO-NE OATT	Laconia & Longhill	NEPOOL PTF				34
			0	**28,794,602**	**28,794,602**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
ISO-NE OATT	Cobble Mt.	NEPOOL PTF		29,159	29,159	1
ISO-NE OATT	Cobble Mt.	NEPOOL PTF				2
ISO-NE OATT	Tracy Substation	NEPOOL PTF				3
ISO-NE OATT	Tracy Substation	NEPOOL PTF				4
ISO-NE OATT	Tracy Substation	NEPOOL PTF				5
ISO-NE OATT	Tracy Substation	NEPOOL PTF				6
ISO-NE OATT	Baldwin Substation	NEPOOL PTF				7
ISO-NE OATT	Baldwin Substation	NEPOOL PTF				8
ISO-NE OATT	Tracy Substation	NEPOOL PTF				9
						10
						11
407	Not Applicable	Not Applicable				12
						13
						14
ISO-NE OATT	Not Applicable	Not Applicable				15
ISO-NE OATT	Not Applicable	Not Applicable				16
ISO-NE OATT	Not Applicable	Not Applicable				17
						18
						19
ISO-NE OATT	Not Applicable	Not Applicable				20
ISO-NE OATT	Not Applicable	Not Applicable				21
ISO-NE OATT	Not Applicable	Not Applicable				22
ISO-NE OATT	Not Applicable	Not Applicable				23
ISO-NE OATT	Not Applicable	Not Applicable				24
ISO-NE OATT	Not Applicable	Not Applicable				25
ISO-NE OATT	Not Applicable	Not Applicable				26
ISO-NE OATT	Not Applicable	Not Applicable				27
ISO-NE OATT	Not Applicable	Not Applicable				28
ISO-NE OATT	Not Applicable	Not Applicable				29
ISO-NE OATT	Not Applicable	Not Applicable				30
ISO-NE OATT	Not Applicable	Not Applicable				31
ISO-NE OATT	Not Applicable	Not Applicable				32
ISO-NE OATT	Not Applicable	Not Applicable				33
ISO-NE OATT	Not Applicable	Not Applicable				34
			0	**28,794,602**	**28,794,602**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
ISO-NE OATT	Not Applicable	Not Applicable				1
ISO-NE OATT	Not Applicable	Not Applicable				2
ISO-NE OATT	Not Applicable	Not Applicable				3
ISO-NE OATT	Not Applicable	Not Applicable				4
ISO-NE OATT	Not Applicable	Not Applicable				5
ISO-NE OATT	Not Applicable	Not Applicable				6
ISO-NE OATT	Not Applicable	Not Applicable				7
ISO-NE OATT	Not Applicable	Not Applicable				8
ISO-NE OATT	Not Applicable	Not Applicable				9
ISO-NE OATT	Not Applicable	Not Applicable				10
ISO-NE OATT	Not Applicable	Not Applicable				11
ISO-NE OATT	Not Applicable	Not Applicable				12
ISO-NE OATT	Not Applicable	Not Applicable				13
ISO-NE OATT	Not Applicable	Not Applicable				14
ISO-NE OATT	Not Applicable	Not Applicable				15
ISO-NE OATT	Not Applicable	Not Applicable				16
ISO-NE OATT	Not Applicable	Not Applicable				17
ISO-NE OATT	Not Applicable	Not Applicable				18
ISO-NE OATT	Not Applicable	Not Applicable				19
ISO-NE OATT	Not Applicable	Not Applicable				20
ISO-NE OATT	Not Applicable	Not Applicable				21
ISO-NE OATT	Not Applicable	Not Applicable				22
ISO-NE OATT	Not Applicable	Not Applicable				23
ISO-NE OATT	Not Applicable	Not Applicable				24
ISO-NE OATT	Not Applicable	Not Applicable				25
ISO-NE OATT	Not Applicable	Not Applicable				26
ISO-NE OATT	Not Applicable	Not Applicable				27
ISO-NE OATT	Not Applicable	Not Applicable				28
ISO-NE OATT	Not Applicable	Not Applicable				29
ISO-NE OATT	Not Applicable	Not Applicable				30
ISO-NE OATT	Not Applicable	Not Applicable				31
ISO-NE OATT	Not Applicable	Not Applicable				32
ISO-NE OATT	Not Applicable	Not Applicable				33
ISO-NE OATT	Not Applicable	Not Applicable				34
			0	**28,794,602**	**28,794,602**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
ISO-NE OATT	Not Applicable	Not Applicable				1
ISO-NE OATT	Not Applicable	Not Applicable				2
ISO-NE OATT	Not Applicable	Not Applicable				3
ISO-NE OATT	Not Applicable	Not Applicable				4
ISO-NE OATT	Not Applicable	Not Applicable				5
ISO-NE OATT	Not Applicable	Not Applicable				6
ISO-NE OATT	Not Applicable	Not Applicable				7
ISO-NE OATT	Not Applicable	Not Applicable				8
ISO-NE OATT	Not Applicable	Not Applicable				9
ISO-NE OATT	Not Applicable	Not Applicable				10
ISO-NE OATT	Not Applicable	Not Applicable				11
ISO-NE OATT	Not Applicable	Not Applicable				12
ISO-NE OATT	Not Applicable	Not Applicable				13
ISO-NE OATT	Not Applicable	Not Applicable				14
ISO-NE OATT	Not Applicable	Not Applicable				15
ISO-NE OATT	Not Applicable	Not Applicable				16
ISO-NE OATT	Not Applicable	Not Applicable				17
ISO-NE OATT	Not Applicable	Not Applicable				18
ISO-NE OATT	Not Applicable	Not Applicable				19
ISO-NE OATT	Not Applicable	Not Applicable				20
ISO-NE OATT	Not Applicable	Not Applicable				21
ISO-NE OATT	Not Applicable	Not Applicable				22
ISO-NE OATT	Not Applicable	Not Applicable				23
ISO-NE OATT	Not Applicable	Not Applicable				24
ISO-NE OATT	Not Applicable	Not Applicable				25
ISO-NE OATT	Not Applicable	Not Applicable				26
ISO-NE OATT	Not Applicable	Not Applicable				27
ISO-NE OATT	Not Applicable	Not Applicable				28
ISO-NE OATT	Not Applicable	Not Applicable				29
ISO-NE OATT	Not Applicable	Not Applicable				30
ISO-NE OATT	Not Applicable	Not Applicable				31
ISO-NE OATT	Not Applicable	Not Applicable				32
ISO-NE OATT	Not Applicable	Not Applicable				33
ISO-NE OATT	Not Applicable	Not Applicable				34
			0	**28,794,602**	**28,794,602**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
ISO-NE OATT	Not Applicable	Not Applicable				1
ISO-NE OATT	Not Applicable	Not Applicable				2
ISO-NE OATT	Not Applicable	Not Applicable				3
ISO-NE OATT	Not Applicable	Not Applicable				4
ISO-NE OATT	Not Applicable	Not Applicable				5
ISO-NE OATT	Not Applicable	Not Applicable				6
ISO-NE OATT	Not Applicable	Not Applicable				7
ISO-NE OATT	Not Applicable	Not Applicable				8
ISO-NE OATT	Not Applicable	Not Applicable				9
						10
						11
ISO-NE OATT	Various	Ashland Substation				12
ISO-NE OATT	Various	Ashland Substation				13
ISO-NE OATT	Various	CL&P System				14
ISO-NE OATT	Various	CL&P System				15
ISO-NE OATT	Various	CTMEEC System				16
ISO-NE OATT	Various	CTMEEC System				17
ISO-NE OATT	Various	GenConn System				18
ISO-NE OATT	Various	GenConn System				19
ISO-NE OATT	NEPCO System	Various		507,172	507,172	20
ISO-NE OATT	NEPCO System	Various				21
ISO-NE OATT	Border of ES System	New Hampshire Co-op.				22
ISO-NE OATT	Border of ES System	New Hampshire Co-op.				23
ISO-NE OATT	Various	PSNH System				24
ISO-NE OATT	Various	PSNH System				25
ISO-NE OATT	Various	Unitil System				26
ISO-NE OATT	Various	Unitil System				27
ISO-NE OATT	Various	Baldwin Substation				28
ISO-NE OATT	Various	Baldwin Substation				29
ISO-NE OATT	Various	NSTAR West System		3,627,543	3,627,543	30
						31
						32
						33
						34
			0	**28,794,602**	**28,794,602**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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.
				1
				2
		-21,140	-21,140	3
		297,432	297,432	4
		2,671,204	2,671,204	5
		-126,961	-126,961	6
		-14,858	-14,858	7
				8
				9
		1,780,802	1,780,802	10
		-84,641	-84,641	11
		-9,906	-9,906	12
				13
				14
		259,753,394	259,753,394	15
		7,095,439	7,095,439	16
		430,505	430,505	17
				18
				19
		2,271	2,271	20
		208,935	208,935	21
		-6,835	-6,835	22
		115,055	115,055	23
		-3,763	-3,763	24
		2,619	2,619	25
		-454	-454	26
		66,400	66,400	27
		1,930	1,930	28
		649,800	649,800	29
		-55,087	-55,087	30
		616,600	616,600	31
		-27,140	-27,140	32
		12,500	12,500	33
		-993	-993	34
0	**0**	**367,750,994**	**367,750,994**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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.
		60,700	60,700	1
		-449	-449	2
		20,400	20,400	3
		-808	-808	4
		1,100,004	1,100,004	5
		258,200	258,200	6
		-4,412	-4,412	7
		435,900	435,900	8
		-24,117	-24,117	9
		25,900	25,900	10
		234	234	11
		85,897	85,897	12
		27,400	27,400	13
				14
				15
		462,087	462,087	16
		-41,653	-41,653	17
		91,703	91,703	18
		-10,562	-10,562	19
		593,386	593,386	20
		-58,974	-58,974	21
		290,117	290,117	22
		-29,599	-29,599	23
				24
				25
				26
				27
				28
				29
				30
		1,635,131	1,635,131	31
		449,691	449,691	32
				33
				34
0	**0**	**367,750,994**	**367,750,994**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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.
		41,726	41,726	1
		2,121	2,121	2
		20,563	20,563	3
		3,581	3,581	4
		24,116	24,116	5
		2,173	2,173	6
		32	32	7
		50,774	50,774	8
		1,942	1,942	9
		19,181	19,181	10
		1,806	1,806	11
		2,776	2,776	12
		306	306	13
		136,535	136,535	14
		9,547	9,547	15
		897	897	16
		103	103	17
		106,835	106,835	18
		9,388	9,388	19
		5,501	5,501	20
		198	198	21
		1,004	1,004	22
		2,329	2,329	23
		18,363	18,363	24
		12,081	12,081	25
		1,232	1,232	26
		7,482	7,482	27
		131	131	28
		71,199	71,199	29
		9,106	9,106	30
		24,595	24,595	31
		1,749	1,749	32
		2,605	2,605	33
		713	713	34
0	**0**	**367,750,994**	**367,750,994**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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.
		18,871	18,871	1
		617	617	2
		672	672	3
		52	52	4
		257	257	5
		26	26	6
		1,429	1,429	7
		1,468	1,468	8
		12,984	12,984	9
				10
				11
		68,544	68,544	12
				13
				14
		70,178,265	70,178,265	15
		1,826	1,826	16
		249,750	249,750	17
				18
				19
		100,116	100,116	20
		638	638	21
		-1	-1	22
		2,631	2,631	23
		-23	-23	24
		691	691	25
		7,397	7,397	26
		-30	-30	27
		9,517	9,517	28
		-41	-41	29
		3,656	3,656	30
		-11	-11	31
		6,571	6,571	32
		-34	-34	33
		8,988	8,988	34
0	**0**	**367,750,994**	**367,750,994**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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.
		-41	-41	1
		1,074	1,074	2
		-2	-2	3
		1,582	1,582	4
		-10	-10	5
		822	822	6
		-3	-3	7
		4,522	4,522	8
		-24	-24	9
		2,404	2,404	10
		-10	-10	11
		6,845	6,845	12
		-27	-27	13
		4,669	4,669	14
		-19	-19	15
		977	977	16
		-5	-5	17
		2,448	2,448	18
		-6	-6	19
		4,872	4,872	20
		-27	-27	21
		4,394	4,394	22
		-21	-21	23
		2,449	2,449	24
		-14	-14	25
		7,064	7,064	26
		-27	-27	27
		2,704	2,704	28
		-14	-14	29
		394,794	394,794	30
		-1,734	-1,734	31
		3,427	3,427	32
		-13	-13	33
		1,633	1,633	34
0	**0**	**367,750,994**	**367,750,994**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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.
		-14	-14	1
		634	634	2
		5,421	5,421	3
		-21	-21	4
		2,027	2,027	5
		-12	-12	6
		28,342	28,342	7
		-101	-101	8
		5,055	5,055	9
		-21	-21	10
		6,521	6,521	11
		-32	-32	12
		525	525	13
		2	2	14
		10,324	10,324	15
		-48	-48	16
		343	343	17
		13,775	13,775	18
		-68	-68	19
		1,001	1,001	20
		-2	-2	21
		103	103	22
		-8	-8	23
		5,974	5,974	24
		-19	-19	25
		2,529	2,529	26
		-6	-6	27
		941	941	28
		1	1	29
		13,131	13,131	30
		-55	-55	31
		1,073	1,073	32
		-6	-6	33
		3,953	3,953	34
0	**0**	**367,750,994**	**367,750,994**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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.
		-18	-18	1
		5,609	5,609	2
		-29	-29	3
		1,190	1,190	4
		-6	-6	5
		7,326	7,326	6
		-37	-37	7
		116	116	8
		-7	-7	9
				10
				11
		8,161	8,161	12
		738	738	13
		10,626,755	10,626,755	14
		943,581	943,581	15
		376,902	376,902	16
		34,134	34,134	17
		19,663	19,663	18
		4,507	4,507	19
		231,459	231,459	20
		20,561	20,561	21
		345,417	345,417	22
		31,093	31,093	23
		3,596,594	3,596,594	24
		323,764	323,764	25
		588,470	588,470	26
		52,137	52,137	27
		129	129	28
		40	40	29
				30
				31
				32
				33
				34
0	**0**	**367,750,994**	**367,750,994**	

Schedule Page: 328 Line No.: 3 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328 Line No.: 6 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328 Line No.: 7 Column: m
This relates to a 2012 True-up adjustment.

Schedule Page: 328 Line No.: 11 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328 Line No.: 12 Column: m
This relates to a 2012 True-up adjustment.

Schedule Page: 328 Line No.: 22 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328 Line No.: 24 Column: m
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Schedule Page: 328 Line No.: 26 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328 Line No.: 28 Column: m
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Schedule Page: 328 Line No.: 30 Column: m
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Schedule Page: 328 Line No.: 32 Column: m
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Schedule Page: 328.1 Line No.: 2 Column: m
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Schedule Page: 328.1 Line No.: 23 Column: m
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Schedule Page: 328.1 Line No.: 24 Column: m
Intracompany revenues are not reported on the FERC form.

Schedule Page: 328.2 Line No.: 2 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328.2 Line No.: 4 Column: m
This relates to the 2017 Annual True-up.

Schedule Page: 328.2 Line No.: 6 Column: m
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FOOTNOTE DATA

Schedule Page: 328.4 Line No.: 11 Column: m
This relates to the 2017 Annual True-up.

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Schedule Page: 328.5 Line No.: 29 Column: m

FOOTNOTE DATA

This relates to the 2017 Annual True-up.

Schedule Page: 328.5 Line No.: 31 Column: m

This relates to the 2017 Annual True-up.

Schedule Page: 328.5 Line No.: 33 Column: m

This relates to the 2017 Annual True-up.

Schedule Page: 328.6 Line No.: 1 Column: m

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This relates to the 2017 Annual True-up.

Schedule Page: 328.6 Line No.: 30 Column: m

Intracompany revenues are not reported on the FERC form.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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	Not Applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
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
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	NSTAR ELECTRIC (EAST)							
2	New England Power Co.	OS					-195,733	-195,733
3	Wellesley Municipal Lgt	OS					15,972	15,972
4	Norwood Municipal Light	OS					3,690,862	3,690,862
5	Bell Rock	OS					68,677	68,677
6	Vermont Elec.Trans Co.	OS					251,393	251,393
7	National Grid	OS					7,000,386	7,000,386
8	ISO-NE	OS					390,406,425	390,406,425
9								
10	NSTAR ELECTRIC (WEST)							
11	National Grid	FNS					70,563	70,563
12	Vermont Elec.Trans Co	OS					65,144	65,144
13	National Grid	OS					1,858,688	1,858,688
14	ISO-NE Sch & Dspch	OS					958,586	958,586
15	ISO-NE Reliability	OS					1,008,926	1,008,926
16	Eversource Energy	FNS					3,844,880	3,844,880
	TOTAL						414,526,625	414,526,625

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Deferred Transm. Exp.	OS					-3,797,420	-3,797,420
2	Retail Transm. Deferral	OS					9,279,276	9,279,276
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						414,526,625	414,526,625

FOOTNOTE DATA

Schedule Page: 332 Line No.: 6 Column: g

Hydro Quebec DC Phase 1 Support (Vermont Electric Transmission Co.)	$	251,393

Schedule Page: 332 Line No.: 7 Column: g

Hydro Quebec DC Phase II Support (New England Hydro Transmission Corp)	$	1,674,003
Hydro Quebec Phase II Support Chester SVC (New England Hydro Transmission Corp.)		331,666
Hydro Quebec DC Phase II Support (New England Hydro Transmission Electric Co.)		4,125,175
Hydro Quebec AC Phase II Support (New England Power Co.)		746,320
Hydro Quebec DC Phase I Support (New England Electric Transmission Corp.)		123,222
	$	7,000,386

Schedule Page: 332 Line No.: 12 Column: g

Hydro Quebec DC Phase I Support (Vermont Electric Transmission Co.)

Schedule Page: 332 Line No.: 13 Column: g

Hydro Quebec DC Phase I Support (New England Electric Transmission Corp.)	$ 31,931
Hydro Quebec DC Phase II Support (New England Hydro Transmission Corp.)	444,326
Hydro Quebec DC Phase II Support (New England Hydro Transmission Electric Co.)	1,094,935
Hydro Quebec AC Phase II Support (New England Power Co.)	199,463
Hydro Quebec Phase II Support - Chester SVC (New England Hydro Transmission Corp.)	88,033
Total	$ 1,858,688

Schedule Page: 332 Line No.: 16 Column: g

Associated Company

Schedule Page: 332.1 Line No.: 1 Column: g

NSTAR West

Schedule Page: 332.1 Line No.: 2 Column: g

NSTAR West

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	393,585
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Net Eversource Energy Service Company rate of return	995,598
7	Bank/Debt Fees Other	619,016
8	Trustee Fees and Expensees	1,099,654
9	Employee Compensation and Shareholder Expenses	649,452
10		
11		
12		
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46	TOTAL	3,757,305

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			3,912,051		3,912,051
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	2,832,160				2,832,160
7	Transmission Plant	82,334,485				82,334,485
8	Distribution Plant	171,556,163				171,556,163
9	Regional Transmission and Market Operation					
10	General Plant	11,901,069		818,433		12,719,502
11	Common Plant-Electric					
12	TOTAL	268,623,877		4,730,484		273,354,361

B. Basis for Amortization Charges

Intangible plant amortization relates primarily to computer software which is amortized over 5,10 or 15 years.

General Plant Amortization includes the amortization of leasehold improvements over the life of the lease.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Production						
13	341	17,574			2.43		
14	342						
15	343						
16	344	64,952			3.17		
17	345	4,530			2.99		
18	346						
19	Subtotal Production	87,056					
20							
21	Transmission						
22	352	145,411			2.09		
23	353	1,637,552			2.33		
24	354	42,012			2.00		
25	355	805,598			2.06		
26	356	377,613			2.22		
27	357	145,641			1.95		
28	358	557,422			2.09		
29	359	55,590			1.53		
30	Subtotal Transmission	3,766,839					
31							
32	Distribution						
33	361	114,634			1.46		
34	362	930,452			2.04		
35	364	451,347			3.06		
36	365	878,235			3.04		
37	366	726,010			1.93		
38	367	1,628,613			2.79		
39	368	667,321			3.31		
40	369	402,766			2.79		
41	370	269,921			5.66		
42	371	11,374			7.40		
43	373	39,056			4.35		
44	Subtotal Distribution	6,119,729					
45							
46	General						
47	390	208,192			3.39		
48	391	32,548			7.36		
49	393	3,140			3.98		
50	394	17,255			4.08		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	395	827			4.43		
13	397	96,998			5.30		
14	398	3,589			4.94		
15	Subtotal General	362,549					
16							
17	Intangible						
18	303	60,554			6.43		
19	Subtotal Intangible	60,554					
20							
21	Total	10,396,727					
22							
23							
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Schedule Page: 336 Line No.: 1 Column: d

	EAST	WEST	TOTAL
Account 404 Intangible Plant	2,822,042	1,090,009	3,912,051

Estimated Depreciation accrual on AFUDC equity for the twelve months ended December 2018. This includes 2018 activity through December: West Transmission Intangible Plant $69 & East Transmission Intangible Plant $(31,819).

WEST:
The total amount of Intangible Plant Depreciation Expense in Account 404 includes a transmission-related component of $0.

Schedule Page: 336 Line No.: 7 Column: b

Estimated Depreciation accrual on AFUDC equity for the twelve months ended December 2018. This includes 2018 activity through December: West Transmission Plant $279,080 & East Transmission Plant $71,614.

	EAST	WEST	TOTAL
Account 403 Transmission Plant	59,363,510	22,970,975	82,334,485

EAST:
Information on Formula Rates Page 106 line 23:
Depreciation related to station specific fixed assets.

Information on Formula Rates Page 106 line 30 and 106.2 line 1:
Amount of depreciation as stipulated in contract.

Schedule Page: 336 Line No.: 8 Column: b

	EAST	WEST	TOTAL
Account 403 Distribution	148,064,145	23,492,018	171,556,163

EAST:
Information on Formula Rates Page 106 line 23:
Depreciation related to station specific fixed assets.

Information on Formula Rates Page 106 line 30 and 106.2 line 1:
Amount of depreciation as stipulated in contract.

Schedule Page: 336 Line No.: 10 Column: b

Estimated Depreciation accrual on AFUDC equity for the twelve months ended December 2018. This includes 2018 activity through December: West Transmission General Plant $4,208 & East Transmission General Plant $260,039.

Company	Function	Depreciation Expense
East	General	8,162,024
West Distribution	General	2,468,295
West Transmission	General	1,270,750
Total		**$ 11,901,069**

EAST:

FOOTNOTE DATA

Information on Formula Rates Page 106 line 23:
Depreciation related to station specific fixed assets.

Information on Formula Rates Page 106 line 30 and 106.2 line 1:
Amount of depreciation as stipulated in contract.

Schedule Page: 336 Line No.: 10 Column: d

	EAST	WEST	TOTAL
Account 404 General Plant	608,786	209,647	818,433

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	NSTAR ELECTRIC COMPANY (EAST)				
2	Assessment charged by the Massachusetts				
3	Department of Public Utilities	8,127,806		8,127,806	
4					
5	Proportionate share of expenses of the Federal				
6	Energy Regulatory Commission (FERC)				
7	Assessment Order No. 472	1,950,836		1,950,836	
8					
9	Legal expense-Transmission		61,286	61,286	
10					
11					
12	NSTAR ELECTRIC COMPANY (WEST)				
13	Assessment charged by the Massachusetts				
14	Department of Public Utilities	1,409,567		1,409,567	
15					
16	Proportionate share of expenses of the Federal				
17	Energy Regulatory Commission (FERC)				
18	Assessment Order No. 472	365,598		365,598	
19					
20	Legal expense-Transmission		31,036	31,036	
21					
22	Legal expense-Distribution		1,263	1,263	
23					
24					
25					
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27					
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45					
46	TOTAL	11,853,807	93,585	11,947,392	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
							2
Electric	928	8,127,806					3
							4
							5
							6
Electric	928	1,950,836					7
							8
Electric	928	61,286					9
							10
							11
							12
							13
Electric	928	1,409,567					14
							15
							16
							17
Electric	928	365,598					18
							19
Electric	928	31,036					20
							21
Electric	928	1,263					22
							23
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		11,947,392					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1		
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
					2
					3
					4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	567,940		
4	Transmission	9,988,067		
5	Regional Market			
6	Distribution	43,335,513		
7	Customer Accounts	27,714,309		
8	Customer Service and Informational	11,457,131		
9	Sales			
10	Administrative and General	50,843,834		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	143,906,794		
12	Maintenance			
13	Production			
14	Transmission	4,411,311		
15	Regional Market			
16	Distribution	36,905,420		
17	Administrative and General	3,026		
18	TOTAL Maintenance (Total of lines 13 thru 17)	41,319,757		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	567,940		
21	Transmission (Enter Total of lines 4 and 14)	14,399,378		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	80,240,933		
24	Customer Accounts (Transcribe from line 7)	27,714,309		
25	Customer Service and Informational (Transcribe from line 8)	11,457,131		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	50,846,860		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	185,226,551		185,226,551
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	185,226,551		185,226,551
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	148,754,360		148,754,360
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	148,754,360		148,754,360
72	Plant Removal (By Utility Departments)			
73	Electric Plant	15,452,569		15,452,569
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	15,452,569		15,452,569
77	Other Accounts (Specify, provide details in footnote):	34,520,274		34,520,274
78				
79				
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	34,520,274		34,520,274
96	TOTAL SALARIES AND WAGES	383,953,754		383,953,754

Schedule Page: 354 Line No.: 21 Column: b

TOTAL	EAST	WEST
14,399,378	12,357,187	2,042,191

Schedule Page: 354 Line No.: 27 Column: b

TOTAL	EAST	WEST
50,846,860	39,988,877	10,857,983

Schedule Page: 354 Line No.: 28 Column: b

OPERATION:	TOTAL	EAST	WEST
PRODUCTION	567,940	558,223	9,717
TRANSMISSION	9,988,067	8,579,055	1,409,012
REGIONAL MARKET	-	-	-
DISTRIBUTION	43,335,513	37,957,198	5,378,315
CUSTOMER ACCOUNTS	27,714,309	23,819,405	3,894,904
CUSTOMER SERVICE AND INFORMATIONAL	11,457,131	9,161,441	2,295,690
SALES	-	-	-
ADMINISTRATIVE AND GENERAL	50,843,834	39,988,877	10,854,957
TOTAL OPERATION	143,906,794	120,064,199	23,842,595
MAINTENANCE:			
PRODUCTION	-	-	-
TRANSMISSION	4,411,311	3,778,132	633,179
REGIONAL MARKET	-	-	-
DISTRIBUTION	36,905,420	29,821,838	7,083,582
ADMINISTRATIVE AND GENERAL	3,026	-	3,026
TOTAL MAINTENANCE	41,319,757	33,599,970	7,719,787
TOTAL OPERATION AND MAINTENANCE:			
PRODUCTION	567,940	558,223	9,717
TRANSMISSION	14,399,378	12,357,187	2,042,191
REGIONAL MARKET	-	-	-
DISTRIBUTION	80,240,933	67,779,036	12,461,897
CUSTOMER ACCOUNTS	27,714,309	23,819,405	3,894,904
CUSTOMER SERVICE AND INFORMATIONAL	11,457,131	9,161,441	2,295,690
SALES	-	-	-

ADMINISTRATIVE AND GENERAL	50,846,860	39,988,877	10,857,983
TOTAL	185,226,551	153,664,169	31,562,382

Schedule Page: 354 Line No.: 68 Column: b

UTILITY PLANT:	TOTAL	EAST	WEST
ELECTRIC PLANT	148,754,360	127,166,419	21,587,941

Schedule Page: 354 Line No.: 73 Column: b

PLANT REMOVAL:	TOTAL	EAST	WEST
ELECTRIC PLANT	15,452,569	10,785,811	4,666,758

Schedule Page: 354 Line No.: 77 Column: b

OTHER ACCOUNTS:

ACCOUNT	TOTAL	EAST	WEST
123	14,855	14,855	-
143	25,225	25,225	-
146	5,881,755	4,375,883	1,505,872
154	482	482	-
163	(140,701)	(160,883)	20,182
182.3	26,713,916	26,503,493	210,423
183	23,595	-	23,595
184	4,055	3,053	1,002
185	992,846	929,692	63,154
186	413,966	189,599	224,367
228	262,930	223,286	39,644
253	11,874	11,874	-
408	(16,614)	(16,614)	-
417	53,659	5,822	47,837
421	2,122	-	2,122
426	164,829	134,670	30,159
454	111,480	111,480	-
TOTAL	34,520,274	32,351,917	2,168,357

Name of Respondent	This Report Is:	Date of Report *(Mo, Da, Yr)*	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Not Applicable

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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)	(4)	(4)	(4)	(4)
3	Net Sales (Account 447)	(23,245,265)	(34,997,010)	(51,218,281)	(68,370,320)
4	Transmission Rights	(232,071)	(232,071)	(232,071)	(232,071)
5	Ancillary Services	(192)	(188)	(186)	(183)
6	Other Items (list separately)				
7	Forward Capacity Market	(990,965)	(1,985,544)	(3,143,386)	(4,329,151)
8	Other	140,676	103,750	(42,165)	(141,313)
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
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41					
42					
43					
44					
45					
46	TOTAL	(24,327,821)	(37,111,067)	(54,636,093)	(73,073,042)

FOOTNOTE DATA

Schedule Page: 397 Line No.: 1 Column: e

Prior to 2018, NSTAR Electric (East) reported revenues as positive and expenses as negative on page 397. Starting in 2018, NSTAR Electric (East) will report revenues as negative and expenses as positive to align with NSTAR Electric (West), fka Western Massachusetts Electric Company.

Schedule Page: 397 Line No.: 4 Column: e

Financial Transmission Rights for NSTAR Electric Company West

Schedule Page: 397 Line No.: 5 Column: e

Ancillary Services for NSTAR Electric Company West

Schedule Page: 397 Line No.: 7 Column: e

Forward Capacity Market revenues for NSTAR Electric Company West

Schedule Page: 397 Line No.: 8 Column: e

Other items (Account 447) include various non-day-ahead and real-time energy items billed by ISO-NE, including: demand response, GIS costs, communication expenses, renewable energy certificate revenue, and other miscellaneous prior period reserve and energy adjustments.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch		$/mw	15,215,712		$/mw	7,097,267
2	Reactive Supply and Voltage		$/mw	6,293,800			
3	Regulation and Frequency Response		$/mwh	84		$/mwh	20
4	Energy Imbalance				272,522	$/mwh	52,501,536
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement		$/mwh&$/mw	125		$/mwh&$/mw	372
7	Other		$/mw	2,795,068			
8	Total (Lines 1 thru 7)			24,304,789	272,522		59,599,195

Schedule Page: 398 Line No.: 1 Column: b

Data is not readily available.

Schedule Page: 398 Line No.: 1 Column: d

East	$12,990,162
West	2,225,550
	$15,215,712

Schedule Page: 398 Line No.: 1 Column: e

Data is not readily available.

Schedule Page: 398 Line No.: 1 Column: g

East	$ 7,095,441
West	1,826
	$ 7,097,267

Schedule Page: 398 Line No.: 2 Column: b

Data is not readily available.

Schedule Page: 398 Line No.: 2 Column: d

East	$ 5,695,723
West	598,077
	$ 6,293,800

Schedule Page: 398 Line No.: 3 Column: b

Data is not readily available.

Schedule Page: 398 Line No.: 3 Column: d

East	-
West	84
	84

Schedule Page: 398 Line No.: 3 Column: e

Data is not readily available.

Schedule Page: 398 Line No.: 3 Column: g

East	-
West	20
	20

Schedule Page: 398 Line No.: 4 Column: e

East	-
West	272,522
	272,522

Schedule Page: 398 Line No.: 4 Column: g

East	$ 43,504,238
West	8,997,298
	$ 52,501,536

Schedule Page: 398 Line No.: 5 Column: d

Allocation of Operating Reserves is not readily available.

Schedule Page: 398 Line No.: 5 Column: g

Allocation of Operating Reserves is not readily available.

Schedule Page: 398 Line No.: 6 Column: b

Data is not readily available.

Schedule Page: 398 Line No.: 6 Column: d

Allocation of Operating Reserves is not readily available.

East	-
West	125
	125

Schedule Page: 398 Line No.: 6 Column: e

Data is not readily available.

Schedule Page: 398 Line No.: 6 Column: g

Allocation of Operating Reserves is not readily available.

East	-
West	372
	372

Schedule Page: 398 Line No.: 7 Column: b

Data is not readily available.

Schedule Page: 398 Line No.: 7 Column: d

East	$ 2,384,218
West	410,850
	$ 2,795,068

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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: NSTAR ELECTRIC COMPANY (EAST)

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	4,309	5	18	3,467	663	93	179		
2	February	3,732	2	18	3,007	546	93	179		
3	March	3,631	7	18	2,852	526	93	253		
4	Total for Quarter 1				9,326	1,735	279	611		
5	April	3,337	2	11	2,674	484	93	179		
6	May	3,801	29	18	2,941	562	93	298		
7	June	4,603	18	18	3,643	662	93	298		
8	Total for Quarter 2				9,258	1,708	279	775		
9	July	5,358	3	17	4,391	788	93	179		
10	August	5,621	29	17	4,633	836	93	152		
11	September	5,370	6	16	4,420	786	93	164		
12	Total for Quarter 3				13,444	2,410	279	495		
13	October	3,830	10	18	3,096	555	93	179		
14	November	3,710	15	18	2,914	538	93	258		
15	December	3,914	18	18	3,045	571	93	298		
16	Total for Quarter 4				9,055	1,664	279	735		
17	Total Year to Date/Year				41,083	7,517	1,116	2,616		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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: NSTAR ELECTRIC COMPANY (WEST)

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	993	5	18	617	329		47		
2	February	883	7	18	546	290		47		
3	March	793	7	18	489	257		47		
4	Total for Quarter 1				1,652	876		141		
5	April	758	3	20	466	242		50		
6	May	855	29	18	509	266		80		
7	June	1,055	18	17	643	334		78		
8	Total for Quarter 2				1,618	842		208		
9	July	1,111	2	17	705	359		47		
10	August	1,191	29	17	715	366		110		
11	September	1,085	6	15	706	363		16		
12	Total for Quarter 3				2,126	1,088		173		
13	October	801	10	19	513	260		28		
14	November	869	15	18	517	274		78		
15	December	915	18	18	544	293		78		
16	Total for Quarter 4				1,574	827		184		
17	Total Year to Date/Year				6,970	3,633		706		

FOOTNOTE DATA

Schedule Page: 400 Line No.: 17 Column: b

Information on Formula Rates Page 106 lines 10 & 13:
Ratio of fixed load per contract divided by station peak load per company records.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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: Not Applicable

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									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	23,999,384
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	276
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,262,017
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	27,440
7	Other	8,824	27	Total Energy Losses	1,349,772
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	26,638,889
9	Net Generation (Enter Total of lines 3 through 8)	8,824			
10	Purchases	26,630,065			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	28,794,602			
17	Delivered	28,794,602			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	26,638,889			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: NSTAR ELECTRIC COMPANY

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	2,445,579	141,725	3,466	5	1800
30	February	2,011,028	133,535	3,003	2	1800
31	March	2,168,569	160,171	2,852	7	1800
32	April	1,983,241	134,566	2,672	2	1100
33	May	1,960,204	54,607	2,942	29	1800
34	June	2,193,155	152,685	3,643	18	1800
35	July	2,710,676	98,274	4,392	3	1700
36	August	2,759,534	81,834	4,644	29	1700
37	September	2,198,665	89,242	4,420	6	1600
38	October	2,028,955	96,413	3,096	10	1800
39	November	2,059,933	96,149	2,914	15	1800
40	December	2,119,350	22,816	3,045	18	1800
41	TOTAL	26,638,889	1,262,017			

Schedule Page: 401 Line No.: 10 Column: b

Purchases include competitive supplier loads.

Schedule Page: 401 Line No.: 29 Column: b

The Total Monthly Energy (MWH) and Monthly Non-Requirements Sales for Resales (columns a and b) are the combined East and West totals. Please see the footnote for line 29, column d regarding the separation of East and West monthly peaks.

Schedule Page: 401 Line No.: 29 Column: d

NSTAR Electric maintains 2 power systems that are not physically integrated. Per instruction 1, the required information on page 401b is furnished separately for each non-integrated system's monthly peaks. NSTAR Electric (East) data is displayed on the main page and NSTAR Electric (West) data is displayed in the footnote.

NSTAR ELECTRIC COMPANY (WEST)

		Monthly Peak	
Month	Megawatts	Day of Month	Hour
Jan	620	5	1800
Feb	549	7	1800
Mar	496	7	1900
Apr	469	16	1400
May	516	29	1900
Jun	645	18	1700
Jul	706	2	1800
Aug	729	29	1800
Sep	707	6	1500
Oct	516	10	2000
Nov	518	15	1800
Dec	548	18	1800

EAST:

Information on Formula Rates Page 106 line 27:

Ratio of 12-month average transmission load divided by reference year 1993 transmission load per contract

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		
38	Quantity (Units) of Fuel Burned	0 0 0	0 0 0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0 0 0	0 0 0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000 0.000 0.000	0.000 0.000 0.000
41	Average Cost of Fuel per Unit Burned	0.000 0.000 0.000	0.000 0.000 0.000
42	Average Cost of Fuel Burned per Million BTU	0.000 0.000 0.000	0.000 0.000 0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000 0.000 0.000	0.000 0.000 0.000
44	Average BTU per KWh Net Generation	0.000 0.000 0.000	0.000 0.000 0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Silver Lake, Pittsfield MA	2010				9,070,493
2	Goodwin Street (Indian Orchard), Springfield MA	2011				11,550,512
3	Cottage Street, Spingfield MA	2014				14,012,752
4	Millers Falls Rd, Montague, MA	2018				10,202,357
5	Chapin Street, Ludlow	2018				5,377,495
6	Feeding Hills Rd, Southwick MA	2018				14,216,525
7	Amherst Rd, Sunderland MA	2018				3,050,041
8	Denslow Rd, Longmeadow MA	2018				1,602,803
9	Water Street, Lee MA	2018				5,723,305
10	Partridge Rd, Pittsfield MA	2018				4,015,705
11	Cadwell Dr, East Springfield MA	2018				7,161,143
12	Plain Rd, Hatfield MA	2018				10,666,517
13	Duchaine Blvd, Bedford MA	2018				5,041,608
14	Summer Street, Plymouth MA	2018				5,834,933
15	Log Plain Rd, Greenfield MA	2018				6,337,947
16	New Windsor Rd, Hinsdale MA	2018				6,303,001
17	Valley Rd, Southhampton MA	2018				6,745,815
18	Roosevelt Ave, Springfield MA	2018				10,056,561
19	Windsor Rd, Savoy MA	2018				6,533,501
20	Tobey Rd, Wareham MA	2018				8,988,091
21	Station Drive, Westwood MA	2018				3,096,131
22						
23						
24						
25						
26						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
						2
						3
						4
						5
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						14
						15
						16
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						20
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						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	OVERHEAD							
2	West Medway Station #446	Eversource/NGRID (Medway)	345.00	345.00	Steel	0.14		1
3	West Medway Station #446	West Walpole Station #447	345.00	345.00	Steel	9.62		1
4	West Walpole Station #447	Eversource/NGRID (Walpole)	345.00	345.00	Steel		0.65	1
5	Stoughton Station #330	West Walpole Station #447	345.00	345.00	Steel	9.04		1
6	Holbrook Station #478	Stoughton Station #330	345.00	345.00	Steel	5.62		1
7	West Medway Station #446	Eversource/NGRID (Walpole)	345.00	345.00	Steel		8.94	1
8	Whitman Station #451	Holbrook Station #478	345.00	345.00	Steel	7.20		1
9	Woburn Station #211	Eversource/NGRID(Billerica)	345.00	345.00	Wood/Steel	6.21		1
10	Pilgrim Station #650	Plymouth (M Standish Tap)	345.00	345.00	Steel	7.31		1
11	Pilgrim Station #650	Plymouth (M Standish Tap)	345.00	345.00	Steel		7.30	1
12	Miles Standish Tap	Whitman Station (Nat'l Grd)	345.00	345.00	Steel	26.00		1
13	West Medway Station #446	West Walpole Station #447	345.00	345.00	Wood/Steel	9.60		1
14	West Medway Station #446	Eversource/NGRID (Milford)	345.00	345.00	Wood/Steel	1.82		1
15	Lexington Station #320	Woburn Station #211	345.00	345.00	Wood/Steel	8.24		1
16	West Medway Station #446	Eversource/NGRID (Milford)	345.00	345.00	Steel	1.87		1
17	Bellingham Tap 336	NEA	345.00	345.00	Wood	0.03		1
18	Bellingham Tap 336	Blackstone Station #309	345.00	345.00	Wood/Steel	2.67		1
19	Blackstone Station #309	(Mass/R.I. Line)	345.00	345.00	Wood/Steel	10.72		1
20	Canal Station #980	Cape Cod Canal (Str 24)	345.00	345.00	Wood/Steel	12.68		1
21	Cape Cod Canal (Str 24)	Cape Cod Canal (Str 27)	345.00	345.00	Steel	0.49		1
22	Cape Cod Canal (Str 27)	Carver Station #726	345.00	345.00	Wood/Steel	7.26		1
23	Carver Station #726	Myles Standish Tap	345.00	345.00	Steel	7.27		1
24	Myles Standish Tap	Cape Cod Canal (Str 4)	345.00	345.00	Steel	9.99		1
25	Cape Cod Canal (Str 4)	Cape Cod Canal (Str 1)	345.00	345.00	Steel	0.60		1
26	Cape Cod Canal (Str 1)	West Barnstable #921	345.00	345.00	Steel	12.71		1
27	Carver Station #726	Eversource/NGRID(Bridgewat	345.00	345.00	Wood/Steel	9.67		1
28	Canal Station #980	Cape Cod Canal (Str 17B)	345.00	345.00	Steel	2.65		1
29	Cape Cod Canal (Str 17B)	Cape Cod Canal (Str 20)	345.00	345.00	Steel	0.61		2
30	Myles Standish Tap	Carver Station #726	345.00	345.00	Steel	7.29		1
31	Eversource/NGRID(Bridgewat	Carver Station #726	345.00	345.00	Steel	9.48		1
32	West Medway Station #446	Bellingham Tap 336	345.00	345.00	Wood/Steel	5.22		1
33	Cape Code Canal (Str 20)	Miles Standish Tap	345.00	345.00	Steel	9.86		1
34	Ludlow S/S	Carpenter Hill S/S	345.00	345.00	SCHF	2.99		1
35	Northfield Mountain Station	Berkshire S/S	345.00	345.00	SCHF	36.91		1
36					TOTAL	1,272.51	226.98	288

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Northfield Mountain Station	Ludlow S/S	345.00	345.00	SCHF	29.30		1
2	Northfield Mountain Station	Vermont Yankee Station	345.00	345.00	SCHF	9.30		1
3	Berkshire S/S	Alps S/S	345.00	345.00	SCHF	14.60		1
4	Ludlow S/S	Barbour Hill S/S	345.00	345.00	SCHF	11.72		1
5	Agawam S/S	Ludlow S/S	345.00	345.00	SCSP	3.20		1
6					DCSP	14.34		
7	Agawam S/S	North Bloomfield 2A	345.00	345.00	SCSP	0.73		1
8					DCSP	5.29		
9	West Medway Station #446	Leland Street Station #240	230.00	230.00	Steel	10.16		1
10	West Medway Station #446	Leland Street Station #240	230.00	230.00	Wood	0.54		
11	West Medway Station #446	Sudbury Station #342	230.00	230.00	Steel		10.16	1
12	West Medway Station #446	Sudbury Station #342	230.00	230.00	Wood/Steel	7.50		
13	Sudbury Station #342	Waltham Station #282	230.00	230.00	Steel		7.20	1
14	Various Locations - East	Various Locations	115.00	115.00	Overhead	415.12	80.47	112
15	Various Locations - West		115.00	115.00	Overhead	236.41	112.26	55
16	Various Locations - West		69.00	69.00	Overhead	5.50		1
17	UNDERGROUND							
18	No. Cambridge Station #509	Woburn Station #211	345.00	345.00	Underground	12.02		2
19	Everett Station #250	No. Cambridge Station #509	345.00	345.00	Underground	9.92		2
20	Everett Station #250	Saugus Nat'l Grid Sta. #90	345.00	345.00	Underground	12.58		1
21	Everett Station #250	Boston Station #514	345.00	345.00	Underground	8.40		2
22	Stoughton Station #330	Hyde Park St. #496 C 3164	345.00	345.00	Underground	11.19		1
23	Stoughton Station #330	K St. Station #385, C 3162	345.00	345.00	Underground	17.40		1
24	Stoughton Station #330	K St. Station #385, C 3163	345.00	345.00	Underground	17.40		1
25	Various Locations - East	Various Locations	115.00	115.00	Underground	167.97		58
26	Various Locations - West		115.00	115.00	Underground	10.15		8
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,272.51	226.98	288

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10	Oper. & Maint.Transm. Line							
11								
12								
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21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,272.51	226.98	288

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
2-900 AL		871	871					2
2500 ACSR		1,777,751	1,777,751					3
2500 ACSR	97,030	14,255,004	14,352,034					4
2-1590 ACSR		9,578	9,578					5
2-1590 ACSR		4,121,756	4,121,756					6
2-1703 ACAR		1,452,209	1,452,209					7
2-1590 ACSR		757,354	757,354					8
2-954 ACSR		3,278,657	3,278,657					9
2-1703 ACAR	187,112	4,558,594	4,745,706					10
2-1703 ACAR	144,712	7,026,074	7,170,786					11
2-1590 ACSR								12
2-954 ACSR		5,547,183	5,547,183					13
2-900 AL		2,784,110	2,784,110					14
2-1113 ACSR		7,069,463	7,069,463					15
2-1113 ACSR		193,004	193,004					16
2-1024.5 ACAR								17
2-900 ACSS	320,652	15,463,479	15,784,131					18
2-900 ACSS		16,767,487	16,767,487					19
2335 ACAR	210,177	22,792,600	23,002,777					20
2335 ACAR								21
2335 ACAR								22
2-954 ACSS		17,596,844	17,596,844					23
2-954 ACSS								24
2338 ACAR								25
2-1703 ACAR								26
2335 ACAR								27
2-1703 ACAR								28
2338 ACAR								29
2-1703 ACAR								30
2-1703 ACAR		963,034	963,034					31
2-900 ACSS								32
2-1703 ACAR								33
2156 ACSR	190,492	5,188,732	5,379,224					34
2-954 ACSR	1,741,464	35,413,260	37,154,724					35
	34,892,305	2,017,737,865	2,052,630,170	7,100,331	10,336,780	91,574	17,528,685	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2-954 ACSR	1,983,154	56,100,158	58,083,312					1
2-954 ACSR	213,175	18,000,544	18,213,719					2
2156 ACSR	574,004	11,275,212	11,849,216					3
2156 ACSR	928,313	12,194,478	13,122,791					4
2-1590 ACSS	12,706,780	79,945,860	92,652,640					5
								6
2-1590 ACSS	5,317,429	27,181,967	32,499,396					7
								8
1113 ACSR		539,270	539,270					9
1113 ACSR								10
1113 ACSR								11
1113 ACSR								12
1113 ACSR		2,002,590	2,002,590					13
Various	2,615,514	482,008,087	484,623,601					14
	7,139,595	417,129,449	424,269,044					15
	165,678	7,428,692	7,594,370					16
								17
CU-2-2500		6,186,283	6,186,283					18
CU-2500	77,817	5,155,676	5,233,493					19
CU-2-2500		5,874,583	5,874,583					20
CU-2500		36,485,845	36,485,845					21
2500CU		41,929,542	41,929,542					22
2500CU		67,787,186	67,787,186					23
2500CU		82,747,899	82,747,899					24
Various	263,540	475,768,992	476,032,532					25
	15,667	14,978,508	14,994,175					26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	34,892,305	2,017,737,865	2,052,630,170	7,100,331	10,336,780	91,574	17,528,685	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
								2
								3
								4
								5
								6
								7
								8
								9
				7,100,331	10,336,780	91,574	17,528,685	10
								11
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								14
								15
								16
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								34
								35
	34,892,305	2,017,737,865	2,052,630,170	7,100,331	10,336,780	91,574	17,528,685	36

FOOTNOTE DATA

Schedule Page: 422 Line No.: 12 Column: l

Cost included in line 11.

Schedule Page: 422 Line No.: 17 Column: l

Cost included in line 18.

Schedule Page: 422 Line No.: 21 Column: l

Cost included in line 20.

Schedule Page: 422 Line No.: 22 Column: l

Cost included in line 20.

Schedule Page: 422 Line No.: 24 Column: l

Cost included in line 23.

Schedule Page: 422 Line No.: 25 Column: l

Cost included in line 23.

Schedule Page: 422 Line No.: 26 Column: l

Cost included in line 23.

Schedule Page: 422 Line No.: 27 Column: l

Cost included in line 4.

Schedule Page: 422 Line No.: 28 Column: l

Cost included in line 11.

Schedule Page: 422 Line No.: 29 Column: l

Cost included in line 11.

Schedule Page: 422 Line No.: 30 Column: l

Cost included in line 10.

Schedule Page: 422 Line No.: 32 Column: l

Cost included in line 18.

Schedule Page: 422 Line No.: 33 Column: l

Cost included in line 11.

Schedule Page: 422.1 Line No.: 10 Column: l

Cost included in line 9.

Schedule Page: 422.1 Line No.: 11 Column: l

Cost included in line 13.

Schedule Page: 422.1 Line No.: 12 Column: l

Cost included in line 13.

Schedule Page: 422.2 Line No.: 10 Column: m

East	$6,362,780
West	737,551
	$7,100,331

Schedule Page: 422.2 Line No.: 10 Column: n

East	$ 4,648,115
West	5,688,665
	$10,336,780

Schedule Page: 422.2 Line No.: 10 Column: o

East	$47,732
West	43,842
	$91,574

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.

2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From	To		Type	Average Number per Miles	Present	Ultimate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	NONE						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
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36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
									2
									3
									4
									5
									6
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	EAST				
2	Sub #2 Boston	Dist.-Unatt.	115.00	13.80	
3	Sub #4 S. Boston	Dist.-Unatt.	115.00	13.80	
4	Sub #12 Boston	Dist.-Unatt.	115.00	13.80	
5	Sub #13 Roslindale	Dist.-Unatt.	13.80	4.16	
6	Sub #16 Somerville	Dist.-Unatt.	13.80	4.16	
7	Sub #17 Newton Center	Dist.-Unatt.	24.00	13.80	
8	Sub #17 Newton Center	Dist.-Unatt.	13.80	4.16	
9	Sub #20 Dedham	Dist.-Unatt.	24.00	13.80	
10	Sub #20 Dedham	Dist.-Unatt.	13.80	4.16	
11	Sub #23 Natick	Dist.-Unatt.	13.80	4.16	
12	Sub #24 Framingham	Dist.-Unatt.	13.80	4.16	
13	Sub #26 Walpole	Dist.-Unatt.	13.80	4.16	
14	Sub #30 Boston	Dist.-Unatt.	13.80	4.16	
15	Sub #33 Waltham	Dist.-Unatt.	13.80	4.16	
16	Sub #34 Lexington	Dist.-Unatt.	13.80	4.16	
17	Sub #36 Allston	Dist.-Unatt.	13.80	4.16	
18	Sub #43 Dorchester	Dist.-Unatt.	13.80	4.16	
19	Sub #49 Boston	Dist.-Unatt.	13.80	4.16	
20	Sub #52 Roxbury	Dist.-Unatt.	13.80	4.16	
21	Sub #53 Boston	Dist.-Unatt.	115.00	13.80	
22	Sub #59 Arlington	Dist.-Unatt.	13.80	4.16	
23	Sub #60 Hyde Park	Dist.-Unatt.	13.80	4.16	
24	Sub #65 West Medway	Dist.-Unatt.	115.00	13.80	
25	Sub #67 Dorchester	Dist.-Unatt.	13.80	4.16	
26	Sub #71 Boston	Dist.-Unatt.	115.00	13.80	
27	Sub #99 S. Boston	Dist.-Unatt.	115.00	13.80	
28	Sub #106 S. Boston	Dist.-Unatt.	115.00	13.80	
29	Sub #110 W. Roxbury	Dist.-Unatt.	115.00	24.00	
30	Sub #110 W. Roxbury	Dist.-Unatt.	115.00	115.00	
31	Sub #124 Watertown	Dist.-Unatt.	13.80	4.16	
32	Sub #126 Hopkinton	Dist.-Unatt.	115.00	13.80	
33	Sub #130 Holliston	Dist.-Unatt.	115.00	13.80	
34	Sub #139 S. Boston	Dist.-Unatt.	13.80	4.16	
35	Sub #143 Roxbury	Dist.-Unatt.	13.80	4.16	
36	Sub #146 Walpole	Dist.-Unatt.	115.00	13.80	
37	Sub #148 Needham	Dist.-Unatt.	13.80	4.16	
38	Sub #148 Needham	Dist.-Unatt.	115.00	13.80	
39	Sub #211 Winchester/Woburn	Dist.-Unatt.	115.00	13.80	
40	Sub #211 Winchester/Woburn	Dist.-Unatt.	13.80	4.16	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Sub #240 Framingham	Dist.-Unatt.	115.00	13.80	
2	Sub #250 Charlestown/Everett	Dist.-Unatt.	115.00	13.80	
3	Sub #250 Charlestown/Everett	Dist.-Unatt.	24.00	13.80	
4	Sub #274 Sherborn	Dist.-Unatt.	115.00	13.80	
5	Sub #277 Newtonville	Dist.-Unatt.	13.80	4.16	
6	Sub #278 Saxonville	Dist.-Unatt.	115.00	13.80	
7	Sub #282 Waltham	Dist.-Unatt.	115.00	13.80	
8	Sub #284 Jamaica Plain	Dist.-Unatt.	13.80	4.16	
9	Sub #285 E. Watertown	Dist.-Unatt.	13.80	4.16	
10	Sub #292 Newton	Dist.-Unatt.	115.00	13.80	
11	Sub #292 Newton	Dist.-Unatt.	13.80	4.16	
12	Sub #293 S. Boston	Dist.-Unatt.	13.80	4.16	
13	Sub #301 Stoneham	Dist.-Unatt.	13.80	4.16	
14	Sub #311 Mattapan	Dist.-Unatt.	13.80	4.16	
15	Sub #315 Brighton	Dist.-Unatt.	115.00	13.80	
16	Sub #316 W. Newton	Dist.-Unatt.	13.80	4.16	
17	Sub #318 Boston	Dist.-Unatt.	13.80	4.16	
18	Sub #320 Lexington	Dist.-Unatt.	115.00	13.80	
19	Sub #321 Dorchester	Dist.-Unatt.	13.80	4.16	
20	Sub #322 Bedford	Dist.-Unatt.	13.80	4.16	
21	Sub #323 Boston	Dist.-Unatt.	13.80	4.16	
22	Sub #325 Woburn	Dist.-Unatt.	13.80	4.16	
23	Sub #329 Brighton	Dist.-Unatt.	115.00	24.00	13.80
24	Sub #329 Brighton	Dist.-Unatt.	115.00	13.80	
25	Sub #340 Boston	Dist.-Unatt.	13.80	4.16	
26	Sub #342 Sudbury	Dist.-Unatt.	115.00	13.80	
27	Sub #344 Hyde Park	Dist.-Unatt.	13.80	4.16	
28	Sub #350 Boston	Dist.-Unatt.	115.00	13.80	
29	Sub #351 E. Lexington	Dist.-Unatt.	13.80	4.16	
30	Sub #355 Maynard	Dist.-Unatt.	13.80	4.16	
31	Sub #360 Sudbury	Dist.-Unatt.	13.80	4.16	
32	Sub #362 Milton	Dist.-Unatt.	13.80	4.16	
33	Sub #369 Newton	Dist.-Unatt.	13.80	4.16	
34	Sub #374 W. Roxbury	Dist.-Unatt.	24.00	4.16	
35	Sub #375 N. Woburn	Dist.-Unatt.	115.00	13.80	
36	Sub #385 S. Boston	Dist.-Unatt.	115.00	13.80	
37	Sub #391 Burlington	Dist.-Unatt.	115.00	13.80	
38	Sub #396 Roxbury	Dist.-Unatt.	24.00	4.16	
39	Sub #402 Somerville	Dist.-Unatt.	115.00	13.80	
40	Sub #416 Maynard	Dist.-Unatt.	115.00	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Sub #430 S. Boston	Dist.-Unatt.	13.80	4.16	
2	Sub #433 Framingham	Dist.-Unatt.	115.00	13.80	
3	Sub #441 Roslindale	Dist.-Unatt.	13.80	4.16	
4	Sub #443 W. Roxbury	Dist.-Unatt.	24.00	4.16	
5	Sub #445 Chelsea	Dist.-Unatt.	24.00	13.80	
6	Sub #450 Waltham	Dist.-Unatt.	115.00	13.80	
7	Sub #454 Dorchester	Dist.-Unatt.	13.80	4.16	
8	Sub #455 Framingham	Dist.-Unatt.	115.00	13.80	
9	Sub #456 Dover	Dist.-Unatt.	115.00	13.80	
10	Sub #467 Watertown	Dist.-Unatt.	115.00	13.80	
11	Sub #468 W. Roxbury	Dist.-Unatt.	24.00	4.16	
12	Sub #469 W. Somerville	Dist.-Unatt.	13.80	4.16	
13	Sub #470 Canton	Dist.-Unatt.	115.00	13.80	
14	Sub #483 Dorchester	Dist.-Unatt.	115.00	13.80	
15	Sub #483 Dorchester	Dist.-Unatt.	13.80	4.16	
16	Sub #488 Chelsea	Dist.-Unatt.	115.00	13.80	
17	Sub #492 Boston	Dist.-Unatt.	115.00	13.80	
18	Sub #496 Hyde Park	Dist.-Unatt.	115.00	13.80	
19	Sub #506 Brookline	Dist.-Unatt.	13.80	4.16	
20	Sub #514 Boston	Dist.-Unatt.	115.00	13.80	
21	Sub #516 W. Roxbury	Dist.-Unatt.	24.00	4.16	
22	Sub #533 Lexington	Dist.-Unatt.	115.00	13.80	
23	Sub #611 New Bedford	Dist.-Unatt.	115.00	13.20	
24	Sub #612 Acushnet	Dist.-Unatt.	115.00	13.20	
25	Sub #624 Acushnet	Dist.-Unatt.	115.00	13.20	
26	Sub #636 New Bedford	Dist.-Unatt.	115.00	13.20	
27	Sub #646 Mattapoisett	Dist.-Unatt.	115.00	13.20	
28	Sub #651 Dartmouth	Dist.-Unatt.	115.00	13.20	
29	Sub #654 Fairhaven	Dist.-Unatt.	115.00	13.20	
30	Sub #657 Dartmouth	Dist.-Unatt.	115.00	13.20	
31	Sub #661 Fall River	Dist.-Unatt.	115.00	34.50	
32	Sub #713 Wareham	Dist.-Unatt.	115.00	23.00	
33	Sub #714 Wareham	Dist.-Unatt.	115.00	23.00	
34	Sub #715 Plymouth	Dist.-Unatt.	115.00	23.00	
35	Sub #721 Plymouth	Dist.-Unatt.	115.00	23.00	
36	Sub #727 Plympton	Dist.-Unatt.	115.00	23.00	
37	Sub #735 Kingston	Dist.-Unatt.	115.00	23.00	
38	Sub #737 Plymouth	Dist.-Unatt.	115.00	23.00	
39	Sub #738 Duxbury	Dist.-Unatt.	115.00	23.00	
40	Sub #739 Marshfield	Dist.-Unatt.	115.00	23.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Sub #745 Rochester	Dist.-Unatt.	115.00	13.20	
2	Sub #817 Cambridge	Dist.-Unatt.	13.80	4.16	
3	Sub #824 Cambridge	Dist.-Unatt.	13.80	4.16	
4	Sub #827 Cambridge	Dist.-Unatt.	13.80	4.16	
5	Sub #828 W. Cambridge	Dist.-Unatt.	117.50	14.40	
6	Sub #831 Cambridge	Dist.-Unatt.	117.50	14.40	
7	Sub #875 E. Cambridge	Dist.-Unatt.	117.50	14.40	
8	Sub #915 Bourne	Dist.-Unatt.	115.00	23.00	
9	Sub #916 Sandwich	Dist.-Unatt.	115.00	23.00	
10	Sub #920 Barnstable	Dist.-Unatt.	115.00	23.00	
11	Sub #933 Falmouth	Dist.-Unatt.	115.00	23.00	
12	Sub #936 Falmouth	Dist.-Unatt.	115.00	23.00	
13	Sub #946 Mashpee	Dist.-Unatt.	115.00	23.00	
14	Sub #961 Hyannis	Dist.-Unatt.	115.00	23.00	
15	Sub #968 Harwich	Dist.-Unatt.	115.00	23.00	
16	Sub #976 Wellfleet	Dist.-Unatt.	115.00	23.00	
17	Sub #975 Orleans	Dist.-Unatt.	115.00	23.00	
18	Primary Network Units (18)	Dist.-Unatt.			
19	Mobile Transformers	Dist.-Unatt.	115.00	13.80	
20	Mobile Transformers	Dist.-Unatt.	115.00	23.00	
21	Minor Substations	Dist.-Unatt.			
22	Sub #150 N. Weymouth	Trans.-Unatt.	115.00	115.00	
23	Sub #211 Winchester/Woburn	Trans.-Unatt.	345.00	115.00	
24	Sub #240 Framingham	Trans.-Unatt.	230.00	115.00	
25	Sub #250 Charlestown/Everett	Trans.-Unatt.	345.00	115.00	
26	Sub #282 Waltham	Trans.-Unatt.	230.00	115.00	
27	Sub #320 Lexington	Trans.-Unatt.	345.00	115.00	
28	Sub #330 Stoughton	Trans.-Unatt.	345.00	345.00	
29	Sub #342 Sudbury	Trans.-Unatt.	230.00	115.00	
30	Sub #385 S. Boston	Trans.-Unatt.	345.00	115.00	
31	Sub #446 W. Medway	Trans.-Unatt.	345.00	230.00	
32	Sub #447 W. Walpole	Trans.-Unatt.	345.00	115.00	
33	Sub #478 Holbrook	Trans.-Unatt.	345.00	115.00	
34	Sub #479 Milford	Trans.-Unatt.	115.00	115.00	
35	Sub #496 Hyde Park	Trans.-Unatt.	345.00	115.00	
36	Sub #509 N. Cambridge	Trans.-Unatt.	345.00	115.00	
37	Sub #514 Boston	Trans.-Unatt.	345.00	115.00	
38	Sub #726 Carver	Trans.-Unatt.	345.00	115.00	22.00
39	Sub #921 Barnstable	Trans.-Unatt.	345.00	115.00	
40	Sub #924 Falmouth tap	Trans.-Unatt.	115.00		

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Sub #958 Barnstable	Trans.-Unatt.	115.00	115.00	
2	Sub #958 Barnstable	Trans.-Unatt.	115.00	115.00	
3	Sub #980 Sandwich	Trans.-Unatt.	345.00	115.00	22.00
4					
5	WEST				
6	Agawam 16C, Agawam	Dist.-Unatt.-With TL	345.00	115.00	
7	Agawam 16C, Agawam	Dist.-Unatt.-With TL	115.00	13.80	
8	Amherst 17K, Amherst	Dist.-Unatt.-With TL	115.00	13.80	
9	Ashfield 38A, Ashfield	Dist.-Unatt.-With TL	115.00	23.00	
10	Berkshire 18C, Hinsdale	Dist.-Unatt.-With TL	345.00	115.00	
11	Berkshire 18C, Hinsdale	Dist.-Unatt.-With TL	115.00	23.00	
12	Blandford 19J, Blandford	Dist.-Unatt.-With TL	115.00	23.00	
13	Breckwood 20A, Springfield	Dist.-Unatt.-With TL	115.00	13.80	
14	Clinton 21S, Springfield	Dist.-Unatt.-With TL	115.00	13.80	
15	Cumberland 22B, Greenfield	Dist.-Unatt.-With TL	115.00	13.80	
16	Doreen 19A, Pittsfield	Dist.-Unatt.-With TL	115.00	23.00	
17	East Springfield 5J, Springfield	Dist.-Unatt.-With TL	115.00	13.80	
18	Franconia 22H, Longmeadow	Dist.-Unatt.-With TL	115.00	13.80	
19	French King 21B, Erving	Dist.-Unatt.-With TL	115.00	13.80	
20	Gunn 15A, Easthampton	Dist.-Unatt.-With TL	115.00	23.00	
21	Ludlow 19S, Ludlow	Dist.-Unatt.-With TL	345.00	115.00	
22	Ludlow 19S, Ludlow	Dist.-Unatt.-With TL	115.00	13.80	
23	Midway 19B, Easthampton	Dist.-Unatt.-With TL	115.00	13.80	
24	Midway 19B, Easthampton	Dist.-Unatt.-With TL	13.80	13.80	
25	Montague 21C, Montague	Dist.-Unatt.-With TL	115.00	13.80	
26	Orchard 27A, Springfield	Dist.-Unatt.-With TL	115.00	13.80	
27	Oswald 30B, Pittsfield	Dist.-Unatt.-With TL	115.00	23.00	
28	Partridge 15E, Pittsfield	Dist.-Unatt.-With TL	115.00	23.00	
29	Piper 21N, West Springfield	Dist.-Unatt.-With TL	115.00	13.80	
30	Plainfield 18K, Plainfield	Dist.-Unatt.-With TL	115.00	23.00	
31	Pleasant 16B, Lee	Dist.-Unatt.-With TL	115.00	23.00	
32	Podick 18G, Amherst	Dist.-Unatt.-With TL	115.00	13.80	
33	Shelburne 29R, Shelburne	Dist.-Unatt.-With TL	69.00	13.80	
34	Silver 30A, Agawam	Dist.-Unatt.-With TL	115.00	13.80	
35	Southwick 29A, Southwick	Dist.-Unatt.-With TL	115.00	23.00	
36	West Springfield 8C,W. Springfield	Dist.-Unatt.-With TL	115.00	13.80	
37	Woodland 17G, Lee	Dist.-Unatt.-With TL	115.00	23.00	
38	Converse, 7J Springfield	Dist.-Unatt.-No TL	13.80	4.16	
39	Dalton 29M, Dalton	Dist.-Unatt.-No TL	23.00	8.32	
40	Silver Lake 5C, Pittsfield	Dist.-Unatt.-No TL	23.00	4.16	

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NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Silver Lake 5C, Pittsfield	Dist.-Unatt.-No TL			
2	Wilbraham Avenue 6N, Springfield	Dist.-Unatt.-No TL	13.80	4.16	
3	Dell Street 29H, Montague	Dist.-Unatt.-No TL	13.80	4.80	
4	Greenfield 28W, Greenfield	Dist.-Unatt.-No TL	13.80	4.80	
5	North Street 23G, Ludlow	Dist.-Unatt.-No TL	13.80	11.50	
6	Pomeroy, Pittsfield				
7	Ravenwood 32N, Ludlow	Dist.-Unatt.-No TL	13.80	4.16	
8	Ravenwood 32N, Ludlow	Dist.-Unatt.-No TL	13.80	0.48	
9	Seymour, Pittsfield				
10	Worthington 4G, Pittsfield	Dist.-Unatt.-No TL	23.00	4.16	
11	Cadwell 50F, Springfield	Trans.-Unatt.	345.00		
12	Erving 38F, Erving	Trans.-Unatt.	115.00		
13	Fairmont 16H, Chicopee	Trans.-Unatt.	115.00		
14	Mount Tom 22C, Holyoke	Trans.-Unatt.	115.00		
15	Northfield Mtn 16R, Northfield	Trans.-Unatt.	345.00	115.00	
16	Pochassic 37R, Westfield	Trans.-Unatt.	115.00	69.00	
17	Shawinigan 55E, Chicopee	Trans.-Unatt.	115.00		
18	South Agawam 42E, Agawam	Trans.-Unatt.	115.00		
19					
20	Total		21760.70	5528.36	57.80
21					
22		Distribution			
23		Transmission			
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
						1
150	2					2
150	2					3
250	4					4
20	3					5
17	2					6
20	2					7
23	3					8
60	3		Capacitors	2	11	9
19	3					10
15	2		Capacitors	1	5	11
21	3					12
26	3					13
13	2					14
22	4					15
25	3					16
30	3		Capacitors	3	4	17
20	3					18
27	3					19
19	3					20
250	4		Capacitors	4	40	21
26	3					22
15	2					23
80	2		Capacitors	1	5	24
14	2					25
150	2		Capacitors	4	40	26
195	3		Capacitors	4	40	27
178	4	1	Capacitors	4	40	28
150	2		Capacitors	1	63	29
			Ph Angle Reg Xfrm	2	330	30
20	2					31
181	3					32
20	1					33
24	3					34
14	2					35
188	3		Capacitors	2	11	36
30	3					37
175	3					38
160	2		Capacitors	6	32	39
20	3					40

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
125	2		Capacitors	3	74	1
188	3		Capacitors	1	63	2
109	2		Capacitors	2	19	3
80	2					4
15	3					5
20	1					6
215	3		Capacitors	2	11	7
15	3					8
						9
250	4					10
10	2					11
15	2					12
10	2					13
31	3					14
195	3		Capacitors	3	30	15
10	2					16
30	3					17
160	2		Capacitors	3	74	18
13	2					19
10	2					20
10	2					21
10	2					22
						23
270	3		Capacitors	2	19	24
						25
128	2		Capacitors	2	57	26
15	3					27
250	4		Capacitors	4	40	28
15	3					29
13	2					30
						31
15	2					32
10	2					33
17	2					34
162	3					35
250	4		Capacitors	2	206	36
160	2		Capacitors	1	5	37
19	2					38
125	2					39
100	2					40

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
20	2					1
188	3		Capacitors	1	5	2
20	2					3
19	2					4
						5
187	3					6
15	2					7
80	2		Capacitors	1	63	8
125	2					9
250	2					10
						11
11	2					12
188	3					13
265	2					14
25	2					15
188	3		Capacitors	1	35	16
250	2					17
250	2					18
28	3					19
250	2		Capacitors	4	40	20
15	2					21
250	2		Capacitors	1	37	22
180	3	1	Capacitors	3	18	23
140	2					24
79	2		Capacitors	1	35	25
100	2		Capacitors	2	10	26
40	1					27
125	2		Capacitors	2	10	28
39	1					29
40	2					30
30	2					31
48	2					32
50	1					33
100	2		Capacitors	2	10	34
50	1		Capacitors	1	2	35
50	1		Capacitors	1	5	36
40	2	1	Capacitors	2	10	37
100	2		Capacitors	2	10	38
100	2					39
50	1		Capacitors	1	5	40

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
25	2					1
21	2					2
11	2					3
10	2					4
168	3					5
210	3					6
188	3					7
50	1		Capacitors	1	5	8
50	1		Capacitors	1	5	9
50	1		Capacitors	1	5	10
150	3		Capacitors	2	10	11
50	1		Capacitors	1	5	12
100	2		Capacitors	3	45	13
175	3		Capacitors	3	49	14
100	2		Capacitors	3	26	15
52	2		Capacitors	2	10	16
100	2		Capacitors	3	23	17
						18
96		2				19
20	1					20
557	306	12				21
			Reactors	2	80	22
400	1	1	Reactors	3	240	23
500	1	1				24
330	1	1	Reactors	2	240	25
450	1		Ph Angle Reg Xfrm	3	495	26
400	1		Reactors	1	160	27
			Reactors	4	640	28
381	1		Reactors	2	40	29
1100	2	1	Reactors	3	320	30
1000	2					31
550	1		Reactors	1	160	32
400	1					33
						34
550	1					35
600	2		Reactors	3	320	36
900	2					37
980	2					38
490	1					39
			Capacitors	1	35	40

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
			Capacitors	1	30	1
			Static Var Comp	1	112	2
1415	3	1				3
						4
						5
1368	6					6
93	2		Capacitor	2	101	7
94	2					8
25	1					9
893	2					10
25	1					11
55	2					12
90	3					13
90	3		Capacitor	5	22	14
77	2					15
72	2		Capacitor	2	11	16
153	3		Capacitor	2	11	17
93	2					18
30	1					19
88	2					20
1330	6					21
30	1	1				22
60	3		Capacitor			23
15	2		Isolation			24
53	2	1				25
123	3		Capacitor	2	11	26
93	2					27
25	1					28
92	2					29
5	1					30
90	3		Capacitor	2	29	31
97	2					32
6	1					33
93	2					34
93	2					35
92	2		Capacitor	4	25	36
50	2		Capacitor	3	35	37
14	2					38
16	2					39
5	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
10	3					1
15	3					2
1	3					3
9	2					4
4	1					5
						6
8	1					7
1	1					8
						9
4	1					10
						11
						12
						13
						14
657	1					15
92	1					16
						17
						18
						19
28930	724	24		153	4,814	20
						21
17735	699	19	Capacitors	126	1,677	22
11195	25	5	Reactors	21	2,200	23
			Ph Angle Reg Xfrmr	5	825	24
			Static Car Comp	1	112	25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

FOOTNOTE DATA

Schedule Page: 426 Line No.: 2 Column: b

Distribution and Unattended

Schedule Page: 426.3 Line No.: 22 Column: b

Transmission and Unattended

Schedule Page: 426.4 Line No.: 6 Column: b

Distribution, Unattended, With Transmission Lines

Schedule Page: 426.4 Line No.: 6 Column: g

2 Banks; 3 Single Phase each bank

Schedule Page: 426.4 Line No.: 21 Column: g

2 Banks; 3 Single Phase each bank

Schedule Page: 426.4 Line No.: 38 Column: b

Distribution, Unattended, With No Transmission Lines

Schedule Page: 426.5 Line No.: 1 Column: c

Spare

Schedule Page: 426.5 Line No.: 6 Column: a

Represents a de-energized site that is not yet closed down.

Schedule Page: 426.5 Line No.: 9 Column: a

Represents a de-energized site that is not yet closed down.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				
5	General Services in a holding company system	Eversource Energy Service Company	Various (see note)	297,515,124
6				
7				
8	Storm Outage Support	Public Service Co. New Hampshire	402	4,418,084
9				
10	Storm Outage Support	The Connecticut Light and Power	402	1,578,424
11				
12	Transfer of Meters	The Connecticut Light and Power	107	2,318,509
13				
14	Transmission System Modifications	The Connecticut Light and Power	107	13,935,764
15				
16	Transfer of Transformers	The Connecticut Light and Power	107	2,707,789
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23	Storm Outage Support	Public Service Co. New Hampshire	402	291,181
24				
25	Storm Outage Support	The Connecticut Light and Power	402	5,258,562
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 5 Column: d

Service Department - Function	Account	Amount
Benefits	183	60
	228	3,478
	232	(327,211)
	401	86,596,540
	402	750
	408	9,393,641
	421	167,631
	426	288,472
	454	1,624
Benefits Total		**96,124,985**
Building Rent and Maintenance	163	69,542
	184	132,704
	232	93,846
	242	3,207
	401	6,399,409
	403	68,703
	426	20,875
	431	9,681
Building Rent and Maintenance Total		**6,797,967**
Corporate Relations	183	(9,763)
	401	4,677,388
	402	46,437
	426	1,384,111
Corporate Relations Total		**6,098,173**
Customer Group	107	3,764,086
	165	(36,429)
	183	0
	186	128,449
	401	57,292,669
	402	565,759
	417	2,718
	426	826,372
	456	(23,429)
Customer Group Total		**62,520,196**
Depreciation	403	16,704,644
Depreciation Total		**16,704,644**
Electric Distribution	107	4,557,905
	108	178,791
	163	1,578
	183	324
	184	(1,608)
	185	4,344

	401	3,906,410
	402	2,040,585
	426	240
Electric Distribution Total		**10,688,569**
Energy Supply	401	2,060,395
	402	19
Energy Supply Total		**2,060,415**
Engineering and Emergency Prep	107	4,078,093
	108	57,008
	186	88,390
	401	3,264,229
	402	66,887
Engineering and Emergency Prep Total		**7,554,607**
Enterprise Energy Strat + Bus Dev	107	111,673
	183	(5,804,756)
	184	118
	232	(693,184)
	401	534,212
	402	5,706
Enterprise Energy Strat + Bus Dev Total		**(5,846,231)**
ERM and Claims + Insurance	184	3,137
	228	584,011
	401	896,431
	402	5,694
ERM and Claims + Insurance Total		**1,489,274**
Finance and Accounting	107	2,001,913
	163	31,265
	165	(4,312)
	183	6,849
	184	36,531
	401	12,139,742
	402	152,498
	426	61
Finance and Accounting Total		**14,364,546**
General Administration	401	648,569
General Administration Total		**648,569**
Human Resources	401	4,260,891
	402	73,322
Human Resources Total		**4,334,213**
Information Technology	101	0
	107	153,973
	111	(0)
	227	0
	230	(0)

	232	32,656
	242	0
	243	0
	401	32,695,936
	402	713,515
	403	45,972
	431	5,683
Information Technology Total		**33,647,734**
Internal Audit + Security	183	(79,376)
	232	(20,540)
	401	2,206,050
Internal Audit + Security Total		**2,106,133**
Investor Relations	401	607,752
	402	955
Investor Relations Total		**608,707**
Legal	107	33,143
	108	6,517
	183	(44,808)
	228	1,026
	401	4,440,934
	402	15,152
	426	174,824
Legal Total		**4,626,788**
Miscellaneous	107	11,194,259
	108	80
	163	4,483,510
	165	154,582
	183	2,125,188
	184	627,818
	228	0
	232	242,342
	237	3,238
	401	4,153,478
	402	5,951,039
	403	(19,633,832)
	408	(9,483,851)
	417	43,141
	419	(27,706)
	421	(12,205)
	426	346,835
	432	(1,259,823)
	454	(87,657)
Miscellaneous Total		**(1,179,564)**
New Business Improvement	401	226,361
	402	17,076

New Business Improvement Total		**243,437**
Operations Administration	107	448
	401	380,921
	426	20,171
Operations Administration Total		**401,540**
Operations Services	107	22,815
	184	289,013
	401	1,781,104
	402	1,077,741
Operations Services Total		**3,170,672**
Safety	107	31
	401	1,543,265
	402	61
	426	510
Safety Total		**1,543,867**
Supply Chain + Env Affs + Property Mgmt	107	1,801,136
	108	29,928
	163	5,634,921
	183	(2,432,196)
	184	712,219
	186	22,050
	228	94,009
	232	35,269
	253	10,890
	401	8,926,978
	402	2,650,219
	417	46,615
	421	286
	454	8
Supply Chain + Env Affs + Property Mgmt Total		**17,532,332**
Taxes	184	1,009
	401	(149,692)
	408	273,937
Taxes Total		**125,254**
Transmission	107	7,908,284
	108	26,342
	183	97,343
	184	(15)
	186	44,771
	401	2,950,539
	402	120,893
	426	140
Transmission Total		**11,148,297**
Grand Total		**297,515,124**

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NSTAR Electric Company

Massachusetts Supplement

to the

FERC Form No. 1

For the year ended December 31,

2018

NSTAR Electric Company
2018
Calculation of Return on Equity

Net utility income available for common shareholders (A)	$	360,879,669
Total utility common equity (B)	$	3,579,899,330
ROE % (A/B)		**10.08%**
Adjusted ROE		**10.02%** (note 4)

(A) Net utility income available for common shareholders (note 1)

Net utility operating income (pg. 117, line 27)				467,950,140
Plus:				
Service quality penalties				-
Less:				
Net interest charges (pg. 117, line 70)			105,583,663	
Total dividends declared (pg. 118, line 29)			1,960,000	
Subtotal			107,543,663	

Total utility plant as % of total utility plant and other property and investments

	balance @ end of year			
Utility plant (pg. 110, line 4)	11,402,328,699			
Accumulated depreciation (pg. 110, line 5)	(2,967,931,831)			
Deferred taxes: MA & Federal (pg. 113, line 63)	(1,701,028,348)			
ARO (GL account 101100)	(28,630,765)			
Customer contributions (pg. 113 line 56)	(47,196,139)			
Total utility plant, net	6,657,541,616	99.56%	99.56%	
Total other property and investments (note 3)	29,311,373	0.44%		
Total utility plant and other property and investments	6,686,852,989	100.00%	107,070,471	107,070,471
Net utility income available for common shareholders				360,879,669

(B) **Total utility common equity** (note 2)

	balance @ beg. of year	balance @ end of year	
Total proprietary capital (pg. 112, line 16)	3,489,079,368	3,773,155,027	3,631,117,198
Plus:			
Discount on capital stock applicable to preferred stock (pg. 112, line 9)	0	0	-
Capital stock expense applicable to preferred stock (pg. 112, line 10)	0	0	-
Less:			
Preferred stock issued (pg. 112, line 3)	43,000,000	43,000,000	43,000,000
Unappropriated undistributed retained earnings (pg. 112, line 12)	(7,584,838)	(7,621,767)	(7,603,303)
Subtotal	3,453,664,206	3,737,776,794	3,595,720,500
			99.56%
Total utility common equity			3,579,899,330

Notes:
(1) Amortization of acquisition premium included due to approval for recovery in DTE 99-19.
(2) Unamortized acquisition premium adjustment is not applicable due to approval for recovery in DTE 99-19.
(3) Other property and investments (pg. 110, line 32) is adjusted for unappropriated undistributed subsidiary earnings (pg. 112, line 12) and other special funds (pg. 110, line 28).
(4) Excluding the impact of transition charge mitigation and LTRCA remuneration earnings ($3,048,601), the transmission and distribution business ROE was 10.02%.

NSTAR Electric Company
Massachusetts Supplement to the FERC Form No. 1

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Name of Respondent	This Report Is:	Date of Report	Year of Report
NSTAR Electric Company	(1) X An Original (2) A Resubmission		December 31, 2018

GENERAL INFORMATION

PRINCIPAL AND SALARIED OFFICERS AS OF DECEMBER 31, 2018*

Titles	Names	Addresses	Annual Salaries (A)
Chairman	James J. Judge	800 Boylston Street, Boston, MA 02199	$495,379
Chief Executive Officer	Werner J. Schweiger	107 Selden Street, Berlin, CT 06037	253,342
President and Chief Operating Officer	Craig A. Hallstrom	1165 Massachusetts Ave, Dorchester, MA 02125	219,234
Executive Vice President and General Counsel	Gregory B. Butler	56 Prospect Street Hartford, CT 06103	238,670
Executive Vice President and Chief Financial Officer	Philip J. Lembo	800 Boylston Street, Boston, MA 02199	251,464
Senior Vice President-Finance and Regulatory and Treasurer	John M. Moreira	247 Station Drive, Westwood, MA 02090	110,650
Vice President-Supply Chain, Environmental Affairs and Property Management	Ellen K. Angley	247 Station Drive, Westwood, MA 02090	126,578
Vice President, Controller and Chief Accounting Officer	Jay S. Buth	107 Selden Street, Berlin, CT 06037	116,033
Vice President-Energy Supply	James G. Daly	247 Station Drive, Westwood, MA 02090	102,600
Vice President-Electric Field Operations	Douglas W. Foley	1165 Massachusetts Ave, Dorchester, MA 02125	223,828
Vice President-Electric System Operations	Michael F. Hayhurst	1165 Massachusetts Ave, Dorchester, MA 02125	110,122
Secretary and Clerk	Richard J. Morrison	800 Boylston Street, Boston, MA 02199	109,662

(A) Represents the portion of the total annual salary allocated to NSTAR Electric by Eversource Energy Service Company.

DIRECTORS AS OF DECEMBER 31, 2018*

Names	Addresses	Fees Paid During Year
Gregory B. Butler	56 Prospect Street Hartford, CT 06103	None
James J. Judge	800 Boylston Street, Boston, MA 02199	None
Philip J. Lembo	800 Boylston Street, Boston, MA 02199	None
Werner J. Schweiger	107 Selden Street, Berlin, CT 06037	None

* By General Laws, Chapter 164 , Section 83, the Return must contain a "list of the names of all their salaried officers and the amount of the salary paid to each," and by Section 77, the department is required to include in its annual report "the names and addresses of the principal officers and of the directors."

Name of Respondent	This Report Is:	Date of Report *(Mo, Da, Yr)*	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2018

GENERAL INFORMATION (Continued)

1. Corporate name of company making this report, NSTAR Electric Company

2. Date of organization, December 26, 1885. On December 31, 2017, affiliate Western Massachusetts Electric Company, was merged into NSTAR Electric Company.

3. Date of incorporation, January 8, 1886

4. Give location (including street and number) of principal business office:
   800 Boylston Street, Boston, MA 02199

5. Total number of stockholders, see page S2-A

6. Number of stockholders in Massachusetts, see page S2-A

7. Amount of stock held in Massachusetts, No. of shares, see page S2-A

8. Capital stock issued prior to June 5, 1894, No. of shares, 481,700; par value $481,700

9. Capital stock issued with approval of Board of Gas and Electric Light Commissioners or Department of Public Utilities since June 5, 1894, No. of shares,
   Total, shares, par value, $, outstanding December 31 of the fiscal year

   see page S2-A

10. If any stock has been issued during the last fiscal period, give the date and terms upon which such issue was offered to the stockholders, and if the whole or any part of the issue was sold at auction, the date or dates of such sale or sales, the number of shares sold and the amounts realized therefrom.

    None

11. Management Fees and Expenses during the Year.

    List all individuals, corporations or concerns with whom the company has any contract or agreement covering management or supervision of its affairs, such as accounting, financing, engineering, construction, purchasing, operation, etc., and show the total amount paid to each for the year.

    Eversource Energy Service Company (Eversource Service) rendered various services at actual costs amounting to $297,515,124.

General Information - continued

Item 5: Total number of stockholders:

Common	1
4.25% preferred	51
4.78% preferred	47

Item 6: Number of stockholders in Massachusetts:

Common	1
4.25% preferred	5
4.78% preferred	7

Item 7: Amount of stock held in Massachusetts:	No. of shares		Par value
Common	200	$	200
4.25% preferred	544	$	54,400
4.78% preferred	484	$	48,400

Item 9: Capital stock issued with approval of Board of Gas and Electric Light Commissioners or Department of Public Utilities since June 5, 1894:

	No. of shares		Par value
Common	200	$	200
4.25% preferred	180,000	$	18,000,000
4.78% preferred	250,000	$	25,000,000

Total shares (including item 9), par value, outstanding at December 31, 2018 :

	No. of shares		Par value
Common	200	$	200
4.25% preferred	180,000	$	18,000,000
4.78% preferred	250,000	$	25,000,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2018

GENERAL INFORMATION (Continued)

Names of the cities or towns in which the company supplies ELECTRICITY, with the number of customers' meters in each place.

City or Town	Number of Customers' Watthour Meters, December 31, 2018	City or Town	Number of Customers' Watthour Meters, December 31, 2018
East:			
Acton	10,555	Mattapoisett	3,956
Acushnet	4,620	Maynard	5,162
Arlington	21,908	Medfield	5,013
Ashland	8,219	Medway	5,359
Aquinnah	562	Millis	3,788
Barnstable	31,023	Milton	10,577
Bedford	6,275	Natick	17,431
Bellingham	1,747	Needham	13,078
Boston	291,594	New Bedford	48,905
Bourne	12,860	Newton	36,650
Brewster	9,229	Norfolk	3,996
Brookline	29,911	Oak Bluffs	4,907
Burlington	11,926	Orleans	8,610
Cambridge	55,680	Pembroke	66
Canton	10,690	Plymouth	31,671
Carlisle	2,064	Plympton	1,331
Carver	5,854	Provincetown	5,905
Chatham	8,602	Rochester	2,454
Chelsea	16,420	Sandwich	11,359
Chilmark	1,866	Scituate	717
Dartmouth	14,833	Sharon	6,853
Dedham	11,374	Sherborn	1,797
Dennis	17,435	Somerville	40,204
Dover	2,290	Stoneham	11,268
Duxbury	7,040	Sudbury	7,422
Eastham	6,846	Tisbury	1,262
Edgartown	6,134	Truro	3,658
Fairhaven	8,310	Walpole	10,837
Falmouth	24,764	Waltham	30,376
Framingham	30,822	Wareham	14,883
Freetown	4,154	Watertown	18,680
Harwich	11,629	Wayland	5,707
Holliston	6,415	Wellfleet	4,885
Hopkinton	7,190	West Tisbury	6,660
Hyde Park	38,468	Weston	4,401
Kingston	6,154	Westport	5,705
Lakeville	462	Westwood	6,365
Lexington	13,582	Winchester	8,641
Lincoln	2,619	Woburn	21,056
Marion	3,259	Yarmouth	18,774
Marshfield	12,497	*Foreign	296
Mashpee	12,126		
		Subtotal East	1,238,673

* Represents "fringe" or "foreign territory". It is electric power provided by NSTAR Electric Company through mutual agreement into another's franchise area(s). Generally this service is rendered due to convenient plant facilities, geographic location, and/or basic economic consideration.

Name of Respondent	This Report Is:	Date of Report	Year of Report
NSTAR Electric Company	(1) X An Original (2) A Resubmission	*(Mo, Da, Yr)*	December 31, 2018

GENERAL INFORMATION (Continued)

Names of the cities or towns in which the company supplies ELECTRICITY, with the number of customers' meters in each place.

City or Town	Number of Customers' Watthour Meters, December 31, 2018	City or Town	Number of Customers' Watthour Meters, December 31, 2018
West:			
Agawam	12,902	Plainfield	388
Amherst	10,484	Richmond	979
Ashfield	967	Russell	365
Becket	1,814	Sandisfield	746
Bernardston	1,082	Savoy	389
Blandford	675	Shelburne	1,154
Buckland	991	Shutesbury	46
Cheshire	53	Southampton	2,579
Chester	64	Southwick	4,387
Chesterfield	674	Springfield	62,799
Chicopee	20	Sunderland	1,986
Colrain	900	Tolland	540
Conway	905	Tyringham	338
Cummington	573	West Springfield	12,629
Dalton	3,111	Washington	319
Deerfield	2,585	Westhampton	847
Easthampton	8,340	Westfield	13
East Longmeadow	4	Whately	883
Erving	423	Wilbraham	3
Gill	715	Windsor	519
Granville	765	Worthington	699
Greenfield	9,263		
Hadley	2,938		
Hancock	118		
Hatfield	1,887	Subtotal West	**211,983**
Hinsdale	1,290		
Huntington	1,105		
Lanesboro	1,742		
Lee	3,604		
Lenox	299		
Leverett	885		
Leyden	357		
Longmeadow	6,020		
Ludlow	9,313		
Middlefield	306		
Montague	4,457		
Montgomery	371		
New Ashford	132		
Northfield	1,531		
Otis	1,938		
Pelham	629		
Peru	446		
Pittsfield	22,697		
		Grand total	**1,450,656**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2018

NOTES RECEIVABLE (Account 141)

1. Give the particulars called for below concerning notes receivable at end of year.
2. Give particulars of any note pledged or discounted.
3. Minor items may be grouped by classes, showing number of such items.
4. Designate any note the maker of which is a director, officer or other employee.

Line No.	Name of Maker and Purpose for Which Received (a)	Date of Issue (b)	Date of Maturity (c)	Interest Rate (d)	Amount End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22				Total	$0

Name of Respondent	This Report is:	Date of Report	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	*(Mo, Da, Yr)*	December 31, 2018

ACCOUNTS RECEIVABLE (Accounts 142, 143)

1. Give the particulars called for below concerning accounts receivable at end of year.
2. Designate any account included in Account 143 in excess of $5,000.

Line No.	Description *(a)*	Amount End of Year *(b)*
1	Customers (Account 142):	
2	Electric	$ 299,302,350
3		
4	Other Electric and Gas Utilities	
5	Other Accounts Receivable (Account 143):	94,876
6	Officers and employees	
7	Due on subscriptions to capital stock (state class series of stock)	
8		
9	Miscellaneous (group and describe by classes):	
10	Receivable for tax refunds	95,232
11	Purchase of Receivables	108,263,015
12	Verizon-Joint owned poles	1,907,679
13	Property Damage Claims	3,371,954
14	Energy efficiency financing program	3,581,023
15	Massachusetts DOT	1,051,268
16	Transmission Wholesale Receivables	2,072,806
17	Lighttower Fiber Networks	179,224
18	RCN	130,625
19	Union Receivable	342,813
20	Comcast Cable	334,613
21	Massachusetts Bay Transportation Authority	764,000
22	ISO New England Inc	10,524,295
23	Barr & Barr Construction	16,748
24	Bell Atlantic Mobile	15,367
25	Berkshire Power LLC	21,078
26	Brightergy	7,047
27	Charter Communications	64,841
28	City of Springfield	27,952
29	Constellation	5,500
30	Direct Energy Business Marketing	83,547
31	DTE Energy Trading Inc	38,000
32	Engie Resources Inc	6,950
33	Fiber Technology Networks LLC	61,835
	Sub Total	$ 432,302,803

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2018

ACCOUNTS RECEIVABLE (Accounts 142, 143)

1. Give the particulars called for below concerning accounts receivable at end of year.
2. Designate any account included in Account 143 in excess of $5,000.

Line No.	Description (a)	Amount End of Year (b)
	Sub Total	432,302,803
34	Graham's Construction Inc	15,879
35	HQ Energy Services	134,877
36	John Carrigan	6,596
37	Mass Power	19,804
38	Mass Technology Collaborative	60,449
39	Mobilitie	5,389
40	Planfield Light	65,569
41	Purenergy Services	331,751
42	Richmond Telephone Company	11,551
43	Skyview Ventures LLC	594,575
44	State of Massachusetts	386,445
45	Time Warner Cable	56,880
46	Town of Ashfield	117,897
47	Town of Leverett	5,823
48	Verizon	34,231
	Total	$ 434,150,519

Name of Respondent	This Report Is:	Date of Report	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2018

PRODUCTION FUEL AND OIL STOCKS (Included in Account 151)
(Except Nuclear Materials)

1. Report below the information called for concerning production fuel and oil stocks.
2. Show quantities in tons of 2,000 lbs., gal., or Mcf, whichever unit of quantity is applicable.
3. Each kind of coal or oil should be shown separately.
4. Show electric fuels separately by specific use.

Line No.	Item (a)	Total Cost (b)	Kinds of Fuel and Oil			
			Oil		Jet fuel	
			Quantity (c) BBLS	Cost (d)	Quantity (e) BBLS	Cost (f)
1	On Hand Beginning of Year					
2	Received During Year					
3	TOTAL					
4	Used During Year (Note A)					
5	Electric #6 oil; Jet fuel					
6	#2 oil					
7	Steam sold from electric stations					
8	Misc. adjustments					
9	Sold or Transferred					
10	TOTAL DISPOSED OF					
11	BALANCE END OF YEAR	$0				

Line No.	Item (g)	Kinds of Fuel and Oil (Continued)			
		Natural Gas			
		Quantity (h) MCF	Cost (i)	Quantity (j)	Cost (k)
12	On Hand Beginning of Year				
13	Received During Year				
14	TOTAL				
15	Used During Year (Note A)				
16	Electric - fossil stations				
17	Electric - jet turbines				
18	Steam sold from electric stations				
19	Misc. adjustments				
20	Sold or Transferred				
21	TOTAL DISPOSED OF				
22	BALANCE END OF YEAR				

Note A -- Indicate specific purpose for which used, e.g., Boiler Oil, Make Oil, Generator Fuel, etc.

Name of Respondent	This Report Is:	Date of Report	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	*(Mo, Da, Yr)*	December 31, 2018

DEFERRED LOSSES FROM DISPOSITION OF UTILITY PLANT (Account 187)

1. In column (a) give a brief description of property creating the deferred loss and the date the loss was recognized. Identify items by department where applicable.
2. Losses on property with an original cost of less than $50,000 may be grouped. The number of items making up the grouped amount shall be reported in column (a).
3. In column (b) give the date of Commission approval of journal entries. Where approval has not been received, give explanation following the respective item in column (a). (See Account 187, Deferred Losses from Sale of Utility Plant.)

Line No.	Description of Property *(a)*	Date J.E. Approved *(b)*	Total Amount of Loss *(c)*	Balance Beginning of Year *(d)*	Current Year		Balance End of Year *(g)*
					Amortizations to Acc. 411.8 *(e)*	Additional Losses *(f)*	
1			$0	$0	$0	$0	$0
2							
3	NONE						
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25	Total		$0	$0	$0	$0	$0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2018

NOTES PAYABLE (Account 231)

Report the particulars indicated concerning notes payable at end of year.

Line No.	Payee (a)	Date of Note (b)	Date of Maturity (c)	Int. Rate (d)	Balance End of Year (e)
1					
2	Commercial Paper	Various	Various	2.500%	$ 278,500,000
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21				Total	$ 278,500,000

Name of Respondent	This Report Is:	Date of Report	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	*(Mo, Da, Yr)*	December 31, 2018

PAYABLES TO ASSOCIATED COMPANIES (Accounts 233, 234)

Report particulars of notes and accounts payable to associated companies at end of year.

Line No.	Name of Company *(a)*	Amount End of Year *(b)*	Interest for Year Rate *(c)*	Interest for Year Amount *(d)*
1	Eversource Service	$ 68,817,702		
2	NSTAR Gas Company	7,445,054		
3	Yankee Gas Company	456,281		
4	Connecticut Light and Power Company	8,488,606		
5	Public Service Company of New Hampshire	442,132		
6	Hopkinton LNG Corp	7,515		
7	Harbor Electric Energy Company	257,995		
8	The Rocky River Realty Company	17,867		
9				
	Totals	$85,933,152		$ -

Name of Respondent	This Report Is:	Date of Report *(Mo, Da, Yr)*	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2018

DEFERRED GAINS FROM DISPOSITION OF UTILITY PLANT (Account 256)

1. In column (a) give a brief description of property creating the deferred gain and the date the gain was recognized. Identify items by department where applicable.
2. Gains on property with an original cost of less than $50,000 may be grouped. The number of items making up the grouped amount shall be reported in column (a).
3. In column (b) give the date of Commission approval of journal entries. Where approval has not been received, give explanation following the respective item in column (a). (See Account 256, Deferred Gains From Sale of Utility Plant.)

Line No.	Description of Property (a)	Date J.E. Approved (b)	Total Amount of Gain (c)	Balance Beginning of Year (d)	Current Year		Balance End of Year (g)
					Amortizations to Acc. 411.6 (e)	Additional Gains (f)	
1	NONE		$0	$0	$0	$0	$0
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23	Total		$0	$0	$0	$0	$0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
NSTAR Electric Company	(1) X An Original (2) A Resubmission		December 31, 2018

OPERATING RESERVES (Accounts 228 & 229)

1. Report below an analysis of the changes during the year for each of the above-named reserves.
2. Show name of reserve and account number, balance beginning of year, credits, debits and balance at end of year . Credit amounts should be shown in black, debit amounts enclosed by parantheses.
3. Each credit and debit amount should be described as to its general nature and the contra account debited or credited shown. Combine the amounts of monthly accounting entries of the same general nature. If respondent has more than one utility department, contra accounts debited or credited should indicate the utility department affected.
4. For accounts 261, Property Insurance Reserve, and 262, Injuries and Damages Reserve, explain the nature of the risks covered by the reserve.
5. For Account 265, Miscellaneous Operating Revenues, report separately each reserve composing the account and explain briefly its purpose.

Note: Per FERC order 390 in 1984, accounts 261-265 were renumbered to accounts 228-229

Line No.	Item	Balance @ 01/01/2018 (debit)/credit	Contra Account Charged	(debit)/credit	Balance @ 12/31/2018
1	**Account 228**				
2					
3	Accumulated provision for injuries and damages	$37,562,761	925	$ 11,329,295	
4			186	3,803,510	
5			131	(7,051,490)	
6					$45,644,076
7					
8	Accumulated provision for pensions and benefits	94,156,648	926	(76,425,637)	
9			182.3	1,757,612	
10			131	(374,715)	
11					19,113,908
12					
13	Accumulated miscellaneous operating provisions	2,701,959	242	7,709,815	
14			131	(3,164,614)	
15					7,247,160
16					
17	Total account 228	$ 134,421,368		$ (62,416,224)	$ 72,005,144
18	**Account 229**				
19					
20	Customer refund reserve	$ 2,977,239			2,977,239
21					
22					
23					
24	Total account 229	$ 2,977,239		$ -	$ 2,977,239

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2018

SALES OF ELECTRICITY TO ULTIMATE CONSUMERS

Report by account, the KWh sold, the amount derived and the number of customers under each filed schedule or contract. Contract sales and unbilled sales may be reported separately in total.

Line No.	Account No.	Schedule (a)	KWh (b)	Revenue (c)	Average Revenue per KWh (cents) (0.0000) (d)	Number of Customers (Per Bills Rendered)	
						July 31 (e)	December 31 (f)
1	see page S12A-D, page 304 of FERC Form 1.						
2							
3							
4							
5							
6							
7							
8							
9							
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12							
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19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31	Total sales to ultimate consumers						

SIR-A

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	[redacted]					
2	All Service Areas					
3	R-1 Residential	6,408,282	1,160,481,879	1,009,426	6,348	0.1811
4	R-2 Residential Assistance	734,459	64,419,504	119,048	6,169	0.0877
5	R-3 Res. Space Heating	885,614	150,357,940	90,398	9,797	0.1698
6	R-4 Res. Space Heating Assist.	89,160	8,028,390	7,195	12,392	0.0900
7	S-1 Street Lighting	2,205	594,416	2,137	1,032	0.2696
8	S-2 Street Lighting Cust Owned	532	42,314	12	44,333	0.0795
9	West					
10	23 Optional Water Heating	186	17,130	6	27,667	0.1032
11	T-0 Small General Service TOU	11	949	1	11,000	0.0863
12	T-2 Large Primary Service TOU	14,489	1,093,122	8	1,811,125	0.0754
13	G-0 Small General Service	30,774	5,095,635	3,321	9,266	0.1656
14	G-2 Primary General Service	44,456	3,929,729	96	463,083	0.0884
15	99 Unmetered	1	328	1	1,000	0.3280
16	Unbilled Revenue	-28,422	-10,511,314			0.3698
17	less: Duplicate Customers			-1,133		
18	Total Residential	8,181,727	1,383,550,022	1,230,516	6,649	0.1691
19						
20	Commercial (Account 442)					
21	All Service Areas					
22	R-1 Residential	17,415	2,141,436	2,751	6,330	0.1230
23	R-3 Res. Space Heating	3,789	419,555	72	52,625	0.1107
24	S-1 Street Lighting	15,372	2,638,517	5,916	2,598	0.1716
25	S-2 Street Lighting Cust Owned	143	4,540	14	10,214	0.0317
26	Greater Boston					
27	G-1 General Service	524,266	94,880,592	74,325	7,054	0.1810
28	G-2 General Service	2,594,552	363,499,929	28,703	90,393	0.1401
29	G-3 General Service TOU	2,305,084	159,767,456	348	6,623,805	0.0693
30	T-1 Optional Time of Use	1,426	30,969	201	7,095	0.0217
31	T-2 Time of Use	3,878,999	364,829,010	3,023	1,283,162	0.0941
32	WR MWRA	104,131	3,772,286	2	52,065,500	0.0362
33	SB-G3 Gen. Service Standby	17,466	1,163,712	1	17,466,000	0.0666
34	Contract-Amtrak Transmission	40,766	1,239,830	1	40,766,000	0.0304
35	Cambridge					
36	G-0 General (Non-Demand)	37,937	3,909,663	5,278	7,188	0.1031
37	G-1 General	204,838	18,094,618	2,000	102,419	0.0883
38	G-2 Lg. Gen. TOU/Second Serv	569,236	39,397,508	461	1,234,785	0.0692
39	G-3 Lg. Gen. TOU/13.8KV Serv	479,945	22,218,133	72	6,665,903	0.0463
40	G-4 Optional General TOU	5,008	369,253	36	139,111	0.0737
41	TOTAL Billed	24,093,811	2,913,062,166	1,427,545	16,878	0.1209
42	Total Unbilled Rev.(See Instr. 6)	-94,427	-14,987,833	0	0	0.1587
43	TOTAL	23,999,384	2,898,074,333	1,427,545	16,812	0.1208

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	G-5 Commercial Space Heating	6,655	535,216	57	116,754	0.0804
2	G-6 Opt. Gen. TOU (Non-Demand)		822			
3	SB-1 Standby Service	27,788	1,448,509	1	27,788,000	0.0521
4	MS-1 Maintenance Service	25,983	590,249	1	25,983,000	0.0227
5	SS-1 Supplemental Service	51,866	3,219,748	1	51,866,000	0.0621
6	SB-G3 Gen. Service Standby	33,514	3,238,737	1	33,514,000	0.0966
7	Contract-MIT MAG Lab	690	136,502	1	690,000	0.1978
8	South Shore / Cape & Vineyard					
9	G-1 General	983,055	97,313,196	44,957	21,867	0.0990
10	G-2 Med. General Time of Use	412,826	29,312,190	419	985,265	0.0710
11	G-3 Lg. General Time of Use	232,141	15,633,448	52	4,464,250	0.0673
12	G-4 General Power	1,239	103,302	15	82,600	0.0834
13	G-5 Commercial Space Heating	12,831	1,371,879	742	17,292	0.1069
14	G-6 All-Electric School	4,738	289,492	7	676,857	0.0611
15	G-7 Optional General TOU	55,191	4,457,166	604	91,376	0.0808
16	West					
17	23 Optional Water Heating	20	6,409	16	1,250	0.3205
18	24 Optional Church	6,076	877,387	191	31,812	0.1444
19	T-0 Small General Service TOU	1,608	129,586	12	134,000	0.0806
20	T-2 Large Primary Service TOU	431,944	30,045,252	158	2,733,823	0.0696
21	T-4 Primary General Service TOU	7,094	587,639	12	591,167	0.0828
22	T-5 Extra Lg. Primary Service TOU	179,137	11,779,548	9	19,904,111	0.0658
23	G-0 Small General Service	537,082	75,106,286	17,249	31,137	0.1398
24	G-2 Primary General Service	274,500	23,904,025	747	367,470	0.0871
25	99 Unmetered	1,224	116,713	104	11,769	0.0954
26	Unbilled Revenue	-59,061	-3,550,230			0.0601
27	less: Duplicate Customers			-2,959		
28	Total Commercial	14,028,514	1,375,030,078	185,601	75,584	0.0980
29						
30	Industrial (Account 442)					
31	All Service Areas					
32	S-1 Street Lighting	1,424	180,501	185	7,697	0.1268
33	Greater Boston					
34	G-1 General Service	1,434	194,627	154	9,312	0.1357
35	G-2 General Service	46,361	7,210,144	485	95,590	0.1555
36	G-3 General Service TOU	656,189	46,525,147	114	5,747,272	0.0710
37	T-2 Time of Use	114,112	13,082,544	120	950,933	0.1146
38	Cambridge					
39	G-0 General (Non-Demand)	25	2,491	5	5,000	0.0996
40	G-2 Lg. Gen. TOU/Second Serv	2,280	194,248	4	570,000	0.0852
41	TOTAL Billed	24,093,811	2,913,062,166	1,427,545	16,878	0.1209
42	Total Unbilled Rev.(See Instr. 6)	-94,427	-14,987,833	0	0	0.1587
43	TOTAL	23,999,384	2,898,074,333	1,427,545	16,812	0.1208

SL2-C

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	G-3 Lg. Gen. TOU/13.8KV Serv	21,539	1,167,935	6	3,589,833	0.0542
2	South Shore / Cape & Vineyard					
3	G-1 General	9,534	1,025,038	120	79,450	0.1075
4	G-2 Med. General Time of Use	44,457	3,700,876	57	779,947	0.0832
5	G-3 Lg. General Time of Use	173,700	9,481,562	35	4,962,857	0.0546
6	G-4 General Power	1,092	113,294	13	84,000	0.1037
7	G-7 Optional General TOU	129	17,450	4	32,250	0.1353
8	Contract-Canal	14,499	1,951,736	2	7,249,500	0.1346
9	West					
10	T-0 Small General Service TOU	117	14,197	2	58,500	0.1213
11	T-2 Large Primary Service TOU	265,753	17,631,449	71	3,743,000	0.0663
12	T-4 Primary General Service TOU	1,528	178,552	5	305,600	0.1169
13	T-5 Extra Lg. Primary Service TOU	260,943	14,339,751	6	43,490,500	0.0550
14	G-0 Small General Service	25,060	3,358,409	393	63,766	0.1340
15	G-2 Primary General Service	55,805	5,453,318	157	355,446	0.0977
16	Unbilled Revenue	-7,010	-928,729			0.1325
17	less: Duplicate Customers			-178		
18	Total Industrial	1,687,971	124,894,540	1,760	959,074	0.0740
19						
20	Street Lighting (Account 444)					
21	All Service Areas					
22	S-1 Street Lighting	37,699	9,268,265	3,758	10,032	0.2458
23	S-2 Street Lighting Cust Owned	61,094	5,002,735	5,117	11,939	0.0819
24	Cambridge					
25	G-0 General (Non-Demand)	917	113,660	228	4,022	0.1239
26	G-1 General	135	12,956	4	33,750	0.0960
27	South Shore / Cape & Vineyard					
28	G-1 General	1,158	177,069	513	2,257	0.1529
29	West					
30	G-0 Small General Service	8	2,075	5	1,600	0.2594
31	99 Unmetered	95	20,493	43	2,209	0.2157
32	Unbilled Revenue	66	2,440			0.0370
33	Total Street Lighting	101,172	14,599,693	9,668	10,465	0.1443
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	24,093,811	2,913,062,168	1,427,545	16,878	0.1209
42	Total Unbilled Rev.(See Instr. 6)	-94,427	-14,987,833	0	0	0.1587
43	TOTAL	23,999,384	2,898,074,333	1,427,545	16,812	0.1208

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
NSTAR Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2018/Q4

FOOTNOTE DATA

Schedule Page: 304 Line No.: 1 Column: a

MWh Sold (Column b) represents all energy deliveries to customers. Revenues (Column c) include delivery revenues as well as energy revenues for those customers who receive their energy supply from NSTAR Electric Company via Basic Service. Since revenues do not include the supply cost to customers of competitive energy suppliers, revenue per KWh sold (Column f) is not necessarily representative of the average customer bill.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2018

OTHER UTILITY OPERATING INCOME (Account 414)

Report below the particulars called for in each column.

Line No.	Property (a)	Amount of Investment (b)	Amount of Revenue (c)	Amount of Operating Expenses (d)	Gain or (Loss) from Operation (e)
1		$0	$0	$0	$0
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32	Totals	$0	$0	$0	$0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2018

OVERHEAD DISTRIBUTION LINES OPERATED

Line No.		Length (Pole Miles)		
		Wood Poles	Steel Towers	Total
1	Miles--beginning of year	11,404		11,404
2	Added during year	56		56
3	Retired during year	47		47
4	Adjustment			0
5	Miles--end of year	11,413		11,413

Distribution System Characteristics--A.C., phase, cycles and operating voltage for light and power.

A.C. three phase 60Hz, 24kV, 13.8kV, 4.16kV, 600V, 480V, 240V, and 208V.

A.C. single phase 60Hz, 8kV, 2.4kV, 277V, 120V and 120/240V.

ELECTRIC DISTRIBUTION SERVICES

Line No.	Item	Electric Services
18	Number at beginning of year	816,865
19	Additions during year:	
20	Purchased	
21	Installed	3,634
22	Associated with utility plant acquired	
23	Total additions	3,634
24	Reductions during year:	
25	Retirements	1,119
26	Associated with utility plant sold	0
27	Total reductions	1,119
28	Number at end of year	819,380

Name of Respondent	This Report Is:	Date of Report	Year of Report
NSTAR Electric Company	X An Original A Resubmission	*(Mo, Da, Yr)*	December 31, 2018

STREET LAMPS CONNECTED TO SYSTEM

Line No.	City or Town (a)	Total (b)	Type												
			Incandescent		Mercury Vapor		Sodium		Metal Halide		Fluorescent	LED		Induction	Fire Alarms
			Municipal (c)	Other (d)	Municipal (e)	Other (f)	Municipal (g)	Other (h)	Municipal (i)	Other (j)	Municipal (k)	Municipal (l)	Other (m)	Municipal (n)	Municipal (o)
	East:														
1	Acton*	769					1		7			761			
2	Acushnet	655					16	62				574	3		
3	Aquinnah	10	3				5	2							
4	Arlington*	3,355					65					3,290			
5	Arlington	46	15		31										
6	Ashland*	809										809			
7	Barnstable	813		1		30		741		40			1		
8	Barnstable*	3,354			2		390		5			2,957			
9	Bedford*	1,625			18		155					1,452			
10	Bellingham	245			186		59								
11	Boston*	25,069	572		1,657	1	891					20,751			1,197
12	Bourne*	1,201					81					1,120			
13	Bourne	463			1	16	90	312		18			26		
14	Brewster*	122					18					104			
15	Brewster	72		2		1		67					2		
16	Brookline*	3,790			103		981					2,446			260
17	Burlington*	2,704			1		153					2,550			
18	Cambridge*	5,016					19					4,997			
19	Cambridge	791			362	1	13	259		6			150		
20	Canton*	2,074	4		12		71					1,987			
21	Carlisle	172	2				3					167			
22	Carver*	737			5		593	136		3					
23	Carver	2		1		1									
24	Chatham*	580					32					548			
25	Chatham	73				1	4	66					2		
26	Chelsea*	1,729				103						1,626			
27	Chelsea	19	8		11										
28	Chilmark*	24	1		1							22			
29	Chilmark	2				2									
30	Dartmouth	270						257		12			1		
31	Dartmouth*	1,723					153				1,570				
32	Dedham*	2,902	6				587					2,309			
33	Dennis	281				4	5	256		2			14		
34	Dennis*	2,301					126					2,175			
35	Dover*	67					67								

Name of Respondent	This Report Is:	Date of Report	Year of Report
NSTAR Electric Company	X An Original A Resubmission	*(Mo, Da, Yr)*	December 31, 2018

STREET LAMPS CONNECTED TO SYSTEM

Line No.	City or Town	Total	Type												
			Incandescent		Mercury Vapor		Sodium		Metal Halide		Fluorescent	LED		Induction	Fire Alarms
			Municipal	Other	Municipal	Other	Municipal	Other	Municipal	Other	Municipal	Municipal	Other	Municipal	Municipal
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
36	Duxbury	461		1	1	12	338	104		5					
37	Eastham	102		1			48	53							
38	Edgartown	19		2			5	12							
39	Edgartown*	288	1									287			
40	Fairhaven*	1,404					6					1,398			
41	Fairhaven	195					4	185		6					
42	Falmouth	703		36		33	9	551		31			43		
43	Falmouth*	2,591					143				10	2,438			
44	Framingham*	4,947					394					4,553			
45	Franklin	7					7								
46	Freetown	260				1	97	147		15					
47	Harwich	157		2		11	7	123		9			5		
48	Harwich*	1,153					65					1,088			
49	Holliston	919			8		911								
50	Hopkinton*	576	1				24					551			
51	Kingston	270			1	9	18	221	1	20					
52	Kingston*	353					353								
53	Lakeville	16					2	14							
54	Lexington*	3,569	1		36		4				902			2,626	
55	Lincoln	267	19		11		2					235			
56	Marion	438			8	4	323	103							
57	Marshfield	1,149				10	819	301		19					
58	Mashpee	164		1		29	1	122		7			4		
59	Mashpee*	393					32					361			
60	Mattapoisett	415					374	41							
61	Maynard*	845			1		8					836			
62	Medfield	347			2		345								
63	Medway*	636			1		69					566			
64	Millis	446					16					430			
65	Milton*	3,292	32				43					3,217			
66	Milton	135			135										
67	Natick*	2,456			1		80					2,375			
68	Needham*	2,863			10		2,853								
69	New Bedford	612				1	34	398		11			168		
70	New Bedford*	7,652					250					7,402			
71	Newton*	8,519					46					8,448			25

Name of Respondent	This Report Is:	Date of Report	Year of Report
NSTAR Electric Company	X An Original / A Resubmission	(Mo, Da, Yr)	December 31, 2018

STREET LAMPS CONNECTED TO SYSTEM

Line No.	City or Town	Total	Type												
			Incandescent		Mercury Vapor		Sodium		Metal Halide		Fluorescent	LED		Induction	Fire Alarms
			Municipal	Other	Municipal	Other	Municipal	Other	Municipal	Other	Municipal	Municipal	Other	Municipal	Municipal
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
72	Newton	88	88												
73	Norfolk	235	2		2		230					1			
74	Oak Bluffs	143			3	19	3	118							
75	Oak Bluffs*	483					22					461			
76	Orleans	115		1			18	89		5			2		
77	Orleans*	300				5	18					277			
78	Pembroke	9						7	2						
79	Plymouth	965		2		42		906		15					
80	Plymouth *	2,646			141		2,403		6			96			
81	Plympton	112					53	56		3					
82	Provincetown*	442					50					392			
83	Provincetown	80				10	4	61					5		
84	Rochester	97			1	3	15	78							
85	Sandwich *	269					16					253			
86	Sandwich	158			1	1	6	125		22		3			
87	Scituate	117			1		109	7							
88	Sharon*	1,646			20		109					1,517			
89	Sherborn	130					129					1			
90	Somerville*	4,440			32		643					3,765			
91	Stoneham*	1,645	25		91		1,529								
92	Sudbury*	633	3		18		23					589			
93	Tisbury	99	1			5	19	73					1		
94	Tisbury*	214										214			
95	Truro	76				3	1	72							
96	Truro *	39					6					33			
97	Wakefield	8					8								
98	Walpole	1,909	6		40		1,863								
99	Waltham*	4,186			1		2,971					1,214			
100	Wareham	653		1	16	40		547		21			28		
101	Wareham*	1,707					1,309					398			
102	Watertown*	2,316			69		70					2,177			
103	Wayland	743	24		9		4					706			
104	Wellfleet	61				3		54		1			3		
105	Wellfleet*	236					14					222			
106	Weston*	828	4				824								

Name of Respondent	This Report Is:	Date of Report	Year of Report
NSTAR Electric Company	X An Original A Resubmission	*(Mo, Da, Yr)*	December 31, 2018

STREET LAMPS CONNECTED TO SYSTEM

Line No.	City or Town	Total	Type												
			Incandescent		Mercury Vapor		Sodium		Metal Halide		Fluorescent	LED		Induction	Fire Alarms
			Municipal	Other	Municipal	Other	Municipal	Other	Municipal	Other	Municipal	Municipal	Other	Municipal	Municipal
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
107	West Tisbury	8				1	1	6							
108	West Tisbury*	59	13									46			
109	Westport	288					92	183		13					
110	Westwood*	1,197					1					1,196			
111	Winchester	59	4		55										
112	Winchester*	1,702					154					1,548			
113	Woburn*	4,243					173					4,070			
114	Yarmouth	391	3	4				360		24					
115	Yarmouth*	2,539					109					2,430			
	Subtotal East	150,798	838	55	3,105	402	25,307	7,275	21	308	2,482	106,439	458	2,626	1,482

* Municipal Light Town Owned

Name of Respondent	This Report Is:	Date of Report	Year of Report
NSTAR Electric Company	X An Original / A Resubmission	(Mo, Da, Yr)	December 31, 2018

STREET LAMPS CONNECTED TO SYSTEM

Line No.	City or Town	Total	Type												
			Incandescent		Mercury Vapor		Sodium		Metal Halide		Fluorescent	LED		Induction	Fire Alarms
			Municipal	Other	Municipal	Other	Municipal	Other	Municipal	Other	Municipal	Municipal	Other	Municipal	Municipal
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	West:														
1	Agawam	2,885			90	62	8	102	2,130	493					
2	Amherst	695				45		1	4	645					
3	Ashfield	31				2			21	8					
4	Becket	122				11			78	33					
5	Bernardston	81			1	7		2	30	41					
6	Blandford	63							47	16					
7	Buckland	120			2	6			96	16					
8	Cheshire	11				1			5	5					
9	Chester	1								1					
10	Chesterfield	36				5			21	10					
11	Chicopee	-								-					
12	Colrain	52				5			34	13					
13	Conway	72			2	1			65	4					
14	Cummington	16			2	5				9					
15	Dalton	108				13			12	83					
16	Deerfield	414			1	7		3	292	111					
17	Easthampton	191			1	20		2	2	166					
18	Erving	12				1				11					
19	Feeding Hills	1								1					
20	Gill	48				10		5	3	30					
21	Granville	79				6	7	-	55	11					
22	Greenfield	418				59	3	12	27	317					
23	Hadley	401			3	22		9	136	231					
24	Hancock	21				6			12	3					
25	Hatfield	210				7		1	100	102					
26	Hinsdale	183				6			131	46					
27	Huntington	146				7			112	27					
28	Lanesborough	399				13		1	280	105					
29	Lee	548			1	15	14	1	436	81					
30	Lenox	53				-			46	7					
31	Leverett	45				4			34	7					
32	Leyden	8			1	3			1	3					
33	Longmeadow	1,665	136		190	14	23	1	1,194	107					
34	Ludlow	2,293			3	35	174	13	1,771	297					

Name of Respondent	This Report Is:	Date of Report	Year of Report
NSTAR Electric Company	X An Original A Resubmission	*(Mo, Da, Yr)*	December 31, 2018

STREET LAMPS CONNECTED TO SYSTEM

Line No.	City or Town	Total	Type													
			Incandescent		Mercury Vapor		Sodium		Metal Halide		Fluorescent	LED		Induction	Fire Alarms	
			Municipal	Other	Municipal	Other	Municipal	Other	Municipal	Other	Municipal	Municipal	Other	Municipal	Municipal	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
35	Middlefield	16				1		-	5	10						
36	Montague	969			1	23		5	858	82						
37	Montgomery	5							3	2						
38	New Ashford	5				2				3						
39	Northfield	179			1	12			133	33						
40	Otis	190		1		8			161	20						
41	Pelham	6							2	4						
42	Peru	10				3			5	2						
43	Pittsfield	841			1	105		46	25	664						
44	Plainfield	15			1	3			8	3						
45	Richmond	22				7			4	11						
46	Russell	111							104	7						
47	Sandisfield	39			2	2			27	8						
48	Savoy	17				1			8	8						
49	Shelburne	146			1	9			107	29						
50	Shutesbury	2				1				1						
51	Southampton	217			1	10			168	38						
52	Southwick	558	1		9	30	2	72	312	132						
53	Springfield	16,715	11	4	1,746	208	1,000	318	11,838	1,590						
54	Sunderland	76				1		1		74						
55	Tolland	26							16	10						
56	Turners Falls	1								1						
57	Tyringham	13				1			12	-						
58	Washington	11				2			3	6						
59	Westfield	2								2						
60	Westhampton	9			1	2			1	5						
61	West Springfield	2,844			42	42	10	36	2,208	506						
62	Whately	58				4		3	8	43						
63	Windsor	19				1			13	5						
64	Worthington	22				1			5	16						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
NSTAR Electric Company	X An Original / A Resubmission		December 31, 2018

STREET LAMPS CONNECTED TO SYSTEM

Line No.	City or Town	Total	Type												
			Incandescent		Mercury Vapor		Sodium		Metal Halide		Fluorescent	LED		Induction	Fire Alarms
			Municipal	Other	Municipal	Other	Municipal	Other	Municipal	Other	Municipal	Municipal	Other	Municipal	Municipal
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
65	Rate OS2	-													
66	Agawam	23							23						
67	Amherst	1,032			1				9	3		1,014	5		
68	Dalton	725							725						
69	Easthampton	1,142			2				655			485			
70	Erving	99			1				5			93			
71	Gill	48										48			
72	Greenfield	1,202			2				2			1,198			
73	Lee	6					6								
74	Montague	54							3			51			
75	Pittsfield	5,357			115				5,239			3			
76	Southwick	58					58								
77	Springfield	67			8		10		1			48			
78	Sunderland	63					1		62						
	Subtotal West	44,448	148	5	2,232	877	1,316	634	29,933	6,358		2,940	5		
	Grand total	195,246	986	60	5,337	1,279	26,623	7,909	29,954	6,666	2,482	109,379	463	2,626	1,482

Name of Respondent:	This report is:		Date of Report:	Year of Report:
NSTAR Electric Company	(1) X	An Original	*(Mo, Da, Yr)*	December 31, 2018
	(2)	A Resubmission		

RATE SCHEDULE INFORMATION

1. Attach copies of all filed rates for general consumers (at end of report)
2. Show below the changes in rate schedules during year and the attached increase or decrease in the annual revenue predicated on the previous year's operations.

Date Effective	M.D.P.U. Number	Rate Schedule	Estimated Annual Effect on Revenues	
			Increases	Decreases
(a)	(b)	(c)	(d)	(e)
01/01/2018	7	R-1 Residential	$108,922,336	
01/01/2018	8	R-2 Residential Assistance		($4,240,292)
01/01/2018	9	R-3 Residential Space Heating	19,295,909	
01/01/2018	10	R-4 Residential Space Heating Assistance	83,771	
01/01/2018	11	G-1 General Service	8,180,751	
01/01/2018	12	G-2 General Service	40,860,387	
01/01/2018	13	G-3 General Service TOU	17,992,382	
01/01/2018	14	T-1 Optional General Time of Use		(57,267)
01/01/2018	15	T-2 Time of Use	38,397,624	
01/01/2018	16	WR MWRA	877,953	
01/01/2018	17	SB-G3 General Service - Standby	343,226	
01/01/2018	18	G-0 General (Non-Demand)		(727,519)
01/01/2018	19	G-1 General		(3,146,609)
01/01/2018	20	G-2 Large General Service TOU		(2,979,535)
01/01/2018	21	G-3 Large General Service TOU 13.8kv	2,081,477	
01/01/2018	22	G-4 Optional General TOU	39,658	
01/01/2018	23	G-5 Commercial Space Heating		(139,311)
01/01/2018	24	G-6 All Electric School	822	
01/01/2018	25	SB1-Standby Service		(2,325,022)
01/01/2018	26	MS-1 Maintenance Service	318,945	
01/01/2018	27	SS-1 Supplemental Service	608,790	
01/01/2018	28	SB-G3 General Service - Standby	333,160	
01/01/2018	29	G1- General		(1,263,341)
01/01/2018	30	G-2 Medium General Time of Use		(876,792)
01/01/2018	31	G-3 Large General Time of Use		(1,574,478)
01/01/2018	32	G-4 General Power	18,432	
01/01/2018	33	G-5 Commercial Space Heating	70,290	
01/01/2018	34	G-6 All Electric School	42,448	
01/01/2018	35	G7-Optional General TOU		(123,146)
01/01/2018	36	23 Optional Water Heating	3,883	
01/01/2018	37	24 Optional Church	110,848	
01/01/2018	38	G-0 Small General Service	12,424,760	
01/01/2018	39	T-0 Small General Service TOU	6,043	
01/01/2018	42	T-2 Large Primary Service TOU	3,591,429	
01/01/2018	41	T-4 Primary General Service TOU	94,319	
01/01/2018	42	T-2 Large Primary Service TOU	8,604,385	
01/01/2018	43	T-5 Extra Large Primary Service TOU	7,790,047	
01/01/2018	44	S1-Street Lighting	391,091	
01/01/2018	45	S-2 Street Lighting Customer Owned		(533,396)
01/01/2018		AM Amtrak Transmission Special Contract	94,334	
01/01/2018		Special Contracts		(304,796)
Sub totals			**$271,579,500**	**($18,291,504)**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2018

ADVERTISING EXPENSES

Line No.	Account No.	Type (a)	General Description (b)	Amount for Year (c)
1	930.1	Television, radio, print, and online advertisting	Brochure inserts for customer bills, television and radio advertising	$272,376
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45			Total	$272,376

Name of Respondent	This Report Is:	Date of Report	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	*(Mo, Da, Yr)*	December 31, 2017

CHARGES FOR OUTSIDE SERVICES

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside services, such as services concerning rates, management, construction, engineering, research, financial, valuation, legal, accounting, purchasing, advertising, labor relations, and public relations, rendered the respondent under written or oral arrangement, for which aggregate payments during the year to any corporation, partnership, organization of any kind, or individual (other than for services as an employee or for payments made for medical and related services) amounted to 5% or more of total charges for outside professional and other consultative services, including payments for legislative services except those which should be reported in Account 426.4, Expenditures for Certain Civil, Political and Related Activities:
   (a) Name and address of person or organization rendering services,
   (b) description of services received during year and project or case to which services relate,
   (c) basis of charges,
   (d) total charges for the year, detailing utility department and account charges.

2. For aggregate payments to any one individual, group, partnership, corporation or organization of any kind in excess of $25,000 (not included in No. 1), there shall be reported the name of the payee, the predominant nature of the services performed and the amount of the payment. Amounts charged to plant accounts shall be reported separately.

3. All charges not reported under No.1 or 2 shall be aggregated by the type of service and each type shall show the amount charged. Amounts charged to plant accounts shall be reported separately for each type.

4. For any such services which are of a continuing nature give date and term of contract and date of Commission authorization, if contract received Commission approval.

5. Designate associated companies.

See the following pages for the detail.

Payments of 5% or more of total charges for outside services

Vendor	Description of Services	Amount	Account Charged
Energy Federation Inc 1 Willow Street Southborough, MA 01772	CL&M	41,770,863	908
	Total	$ 41,770,863	

Year 2018 Total payments of greater than $25,000 but less than 5% of total	Predominant nature of services performed	Total Paid	Amount charged to plant accounts	Plant account charged
3M COMPANY INC	Operations	$ 32,075	$	
A & G INDUSTRIAL SERVICES INC	Environmental	97,583	84,779	107
A Z CORPORATION	Construction	227,572	224,894	107/108
ABB POWER INC	Construction	6,295,501	6,276,997	107/108
ABODE ENERGY MANAGEMENT	Operations	1,169,882		
ACRT INC	Operations	1,783,862	33,348	107
ACTION FOR BOSTON COMMUNITY DEV	C&LM	28,194,458		
ADVANCED ENERGY GROUP	CL&M	5,443,197		
ADVANCED MICROGRID SOLUTIONS INC	CL&M	1,166,060		
AECOM INC	IT Services	8,072,954	147,754	107/108
AERIAL PRODUCTIONS COMPANY	Environmental	150,455	8,850	107
AFL TELECOMMUNICATIONS LLC	IT Services	51,419	51,419	107
AIR GRAPHICS	Operations	45,688		
AIR TECHNOLOGIES INC	Maintenance	59,142	55,680	107/108
ALECTRA UTILITIES CORPORATION	CL&M	437,675		
ALKAT UTILITY SERVICES INC	Construction	332,245	304,191	107/108
ALLIANCE POWER GROUP LLC	CL&M	298,890		
ALTEC INDUSTRIES INC	Transportation	11,109,181	11,106,454	107
AMERESCO	Consulting	5,335,326	4,852,335	107
AMERICAN ELECTRICAL TESTING CO	Construction	113,801	113,801	107/108
AMERICAN PLUMB & HEATING CORP	Construction	162,762	81,068	107/108
ANDELMAN & LELEK ENGINEERING	Engineering	233,826		
APEX ANALYTICS LLC	C&LM	124,119		
APPLIANCE RECYCLING CENTERS OF AMERICA	Environmental	1,233,298		
ARTCO	Operations	38,048		
ARTHUR J HURLEY CO INC	Construction	144,688	141,761	107/108
ARTIS ENERGY	CL&M	559,535		
ASPLUNDH TREE EXPERT CO	Vegetation	19,378,438	3,757,176	107/108
ASSOCIATED CREDIT SERVICES INC	Financial	158,179		
ATL CONSTRUCTION INC	Construction	700,041	700,041	107/108
ATLANTIC CLEANING PRODUCTS	Maintenance	25,337	25,337	107
AUTOGRID SYSTEMS INC	IT Services	150,000		
AVO TRAINING & INSTITUTE INC.	Consulting	42,676		
AVTEC INC	Construction	91,701	91,701	107
AZ CORPORATION	Construction	2,462,826	2,459,703	107/108
B & D GENERAL CONTRACTORS INC	Construction	166,644	166,644	107
B & E EXCAVATING	Construction	1,602,209	1,489,339	107/108
B2Q ASSOCIATES INC	Engineering	39,668		
BAC SALES DBA FOREVERLAWN	Vegetation	152,559	108,500	107/108
BADGER DAYLIGHTING CORP	Construction	1,128,958	920,368	107/108
BARD RAO & ATHANAS CONSULTING ENG	Consulting	40,730		
BARKER ADVT SPECIALTY CO, INC	Operations	29,141		
BARNES TREE SERVICE INC	Vegetation	2,951,775	36,384	107/108
BARNHART NORTHEAST INC	Rental Services	304,199	282,445	107/108
BAY STATE PIPING COMPANY INC	Operations	3,896,374	3,353,963	107/108
BEALS & THOMAS INC	Engineering	101,916	92,041	107/108
BERKSHIRE FENCE CO	Facilities	80,810	79,862	107/108
Berkshire Fence Co.	Construction	92,741	92,741	107/108
BEST ELECTRICIANS INC	Construction	29,674	27,882	107/108
BETTENCOURT ELECTRIC	Construction	85,604	77,696	107/108
BHI ENERGY POWER SERVICES LLC	Operations	420,753	319,484	107/108
BLACK & VEATCH MANAGEMENT CONSULTING LLC	Engineering	463,888	463,888	107
BLUROC LLC	Construction	177,009	176,879	107/108
BOATHOUSE GROUP INC	Consulting	1,341,844	38,796	107
BOND BROTHERS INC	Construction	13,081,193	13,037,047	107/108
BOSCO CRANE CO. INC.	Construction	187,332	187,332	107/108
BOSTON POLICE DEPARTMENT	Operations	2,526,297	2,000,148	107/108
BOSTON GLOBE MEDIA PARTNERS LL	C&LM	318,731		
BOWDITCH & DEWEY LLP	Legal	96,943	95,337	107

Year 2018 Total payments of greater than $25,000 but less than 5% of total	Predominant nature of services performed	Total Paid	Amount charged to plant accounts	Plant account charged
BP PRUCENTER ACQUISITION LLC	Consulting	168,850	167,168	107
BRAYTON-WILSON-COLE CORP	Construction	540,616	483,831	107/108
BRIGHTFIELDS DEVELOPMENT LLC	Construction	362,713	362,713	107
BRIGHTVIEW LANDSCAPES LLC	Facilities	237,419	237,419	107
BRODIE TOYOTA - LIFT INC	Construction	32,794	31,142	107/108
BSC GROUP INC	Engineering	321,565	321,526	107/108
BUILDINGIQ INC	IT Services	55,844		
BURNS & MCDONNELL ENGINEERING	Engineering	3,860,044	3,809,535	107
C3 IOT INC	C&LM	1,490,116		
CAMBRIDGE POLICE DETAIL FUND	Operations	231,124	175,210	107/108
CANON FINANCIAL SERVICES INC	Financial	25,003		
CAPE POWER SYSTEMS CONSULTING	Consulting	29,550	29,550	107
CASE SNOW MANAGEMENT, INC.	Facilities	337,605	95,417	107
CENTER FOR ECOLOGICAL TECH	Environmental	92,395		
CENTRAL CONNECTICUT CABLE	Operations	139,554		
CENTRAL MASSACHUSETTS PHYSICAL	Operations	34,751		
CHA CONSULTING INC	Consulting	68,022	64,822	107
CHAIN ELECTRIC CO	Operations	257,287		
CHARTER CONTRACTING CO LLC	Construction	63,695	60,920	107/108
CIANBRO CORPORATION	Staffing	248,569		
CISTERNELLI BROTHERS INC	Operations	100,200	100,200	107/108
CITY OF CHELSEA	Operations	128,282	96,493	107/108
CITY OF NEW BEDFORD	Operations	224,031	152,033	107/108
CITY OF NEWTON	Operations	304,470	167,290	107/108
CITY OF PITTSFIELD	Operations	226,342	11,471	107/108
CITY OF SOMERVILLE	Operations	379,237	303,176	107/108
CITY OF SPRINGFIELD	Operations	449,251	28,136	107/108
CITY OF WALTHAM	Operations	96,579	68,008	107/108
CITY OF WOBURN	Operations	313,956	166,386	107/108
CLEAN EARTH OF CONNECTICUT	Environmental	113,751	113,751	107
CLEAN HARBORS ENV SERVICES INC	Environmental	6,888,430	2,399,470	107/108
CLEARESULT CONSULTING INC	CL&M	30,840,416		
CLOHESSY HARRIS & KAISER LLC	Construction	34,890	34,890	107/108
CMC ENERGY SERVICES INC	C&LM	483,013		
COCHRANE USA INC	Facilities	693,625	693,625	107
COLLINS CRANE & RIGGING SERV	Construction	349,574	349,574	107/108
COMMONWEALTH OF MASSACHUSETTS	Operations	63,018	8,536	107/108
COMPLETE RECYCLING SOLUTIONS LLC	Operations	194,402		
CONCENTRIC ENERGY ADVISORS	C&LM	87,096		
CONCORDE SPECIALTY GASES INC	Maintenance	42,437	33,439	107
CONSULTING ENGINEERS GROUP INC	Engineering	123,375	103,875	107/108
CON-TEST ANALYTICAL LABORATORY	Environmental	83,734	81,220	107/108
CONTI ENTERPRISES INC	CL&M	23,884,088	23,809,088	107
CONTI SOLAR LLC	Construction	20,157,498	19,962,432	107
CONTRACT CALLERS INC	Consulting	205,535		
CONTROLPOINT TECHNOLOGIES	Consulting	533,331	529,705	107/108
CONVERGENT OUTSOURCING INC	Consulting	147,910		
CORNERSTONE ENERGY SERVICES INC	Engineering	99,562	92,870	107/108
COX INDUSTRIES	Operations	123,895	123,454	107/108
CREDIT COLLECTION SERVICES	Operations	165,334		
CROW INSIGHT LLC	IT Services	26,846		
CROWLEY REAL ESTATE APPRAISERS	Operations	36,681	1,200	107
CUSTOMERTIMES CORP	Staffing	77,071		
D&M ELECTRICAL CONTRACTING INC	Staffing	190,749		
DANA LEASING SYSTEM	Transportation	35,460	35,460	107/108
DANIEL BURKE ELECTRICAL	Construction	3,980,102	2,812,534	107/108
DAVEY TREE EXPERT COMPANY	Vegetation	105,063	84,051	107/108
DAVIES OFFICE REFURBISHING INC	Consulting	26,889	26,889	107
DECLAN FENNELL	Operations	29,087		

Year 2018 Total payments of greater than $25,000 but less than 5% of total	Predominant nature of services performed	Total Paid	Amount charged to plant accounts	Plant account charged
DEJANA TRUCK & UTILITY EQUIPMENT CO INC	Construction	636,671	636,671	107
DGT SURVEY GROUP	Engineering	53,870	53,870	107
DIG SAFE SYSTEM INC	Operations	158,762		
DIGITALGRID INC	Consulting	25,341		
DISTINCTIVE GARDENS & TREE CARE LLC	Facilities	596,866	213,578	107/108
DISTRAN PACKAGED SUBSTATIONS LLC	Construction	348,762	348,762	107
DISTRIBUTION & CONTROLS PRODUCTS LLC	Operations	46,756	44,434	107/108
DMI	Consulting	156,164		
DOBLE ENGINEERING COMPANY	Engineering	152,616	2,538	107/108
DOOSAN GRIDTECH SERVICES LLC	IT Services	40,000	40,000	107
DUNSKY ENERGY CONSULTING	Consulting	152,023		
DUQUESNE LIGHT COMPANY	CL&M	548,100		
DURHAM HIGH VOLTAGE	CL&M	243,115		
E HOLLAND CONTRACTING INC	Staffing	1,816,773		
E J ELECTRIC INSTALLATION CO	Construction	1,315,266	819,130	107/108
E S BOULOS COMPANY	Consulting	551,263		
E S G ENERGY SERVICES	CL&M	374,715		
EAST RIVER ENERGY	CL&M	59,843		
ECOVA INC	CL&M	3,434,671		
EDF RENEWABLES DISTRIBUTED SOLUTIONS INC	Construction	2,853,447	2,853,447	107
EDISON POWER CONSTRUCTORS INC	Construction	2,468,578		
ELDCO LANDSCAPE & TREE SERVICE	Vegetation	37,611	12,062	107/108
ELECCOMM CORPORATION	Construction	1,288,430	166,289	107/108
ELECNOR HAWKEYE LLC	Construction	3,219,911	2,721,899	107/108
ELECTRIC POWER SYSTEMS INTL	Construction	167,524	167,524	107
ELECTRIC SUPPLY CENTER	Maintenance	473,538	468,893	107/108
ELECTRO WIRE INC	Maintenance	856,458	856,458	107
ELUTIONS INC	Consulting	85,072		
EMCOR SERVICES NORTHEAST INC	Construction	40,490	40,490	107/108
ENERGIZED LINE CONSTRUCTION	Construction	118,124		
ENERGY & RESOURCE SOLUTIONS	CL&M	179,265		
ENERGY EFFICIENCY ADVISERS INC	CL&M	122,300		
ENERGY FEDERATION INC	CL&M	41,770,863		
ENERGY INITIATIVES GROUP LLC	C&LM	2,541,479	2,480,615	107/108
ENERGY ORBIT	CL&M	1,181,838		
ENERGY RESOURCES USA LLC	CL&M	317,320		
ENERGY SOLUTIONS	CL&M	8,018,193		
ENERNEX CORPORATION	Consulting	64,000	64,000	107/108
ENGINEERED SOLUTIONS INC	Engineering	49,045		
ENTERGY LOUISIANA LLC	CL&M	879,097		
ENTERPRISE RENT A CAR	Operations	105,603		
ENVIROMED SERVICES INC	Engineering	52,024	48,984	107/108
ENVIRONMENTAL SYSTEMS CORP	Environmental	1,901,271	1,894,864	107/108
EPRI	Consulting	68,084	49,725	107
EPS TECHNOLOGY INC	IT Services	105,462	105,462	107/108
EPSILON ASSOCIATES INC	Engineering	1,083,386	1,083,386	107
EVANS LINE	CL&M	978,185		
EXECUSPACE CONSTRUCTION CORP	Construction	447,549	447,549	107/108
EXPERIAN MARKETING SOLUTIONS INC	CL&M	61,985		
EXPONENT INC	Engineering	231,850	39,683	107
EXTRA DUTY SOLUTIONS	Staffing	255,101	192,569	107/108
FARLAND CORP	Engineering	55,957	55,957	107/108
FARRISSEY TELE- COMM, INC.	Construction	298,573	242,444	107/108
FEENEY BROTHERS EXCAVATION LLC	Staffing	181,537	6,302	107/108
FIRE EQUIPMENT INC	Construction	50,349		
FIRE SYSTEMS TECHNOLOGY INC	Construction	136,972	40,084	107/108
FISCHBACH & MOORE ELECTRIC GROUP LLC	CL&M	79,707		
FRAN DAN BOLT AND SCREW CORP	Operations	34,025	24,821	107/108
FRANKLIN UTILITY CORP	Construction	335,300	276,603	107/108

Year 2018 Total payments of greater than $25,000 but less than 5% of total	Predominant nature of services performed	Total Paid	Amount charged to plant accounts	Plant account charged
FRAUNHOFER USA, INC.	Operations	67,000		
FREETOWN POLICE DEPT	Operations	51,682	42,102	107/108
FRUEAN UTILITIES INC	Construction	212,853	175,543	107/108
FUSS & ONEILL INC	CL&M	79,971	78,595	107/108
G & S MOTOR EQUIPMENT COMPANY	Operations	80,394		
G GREENE CONSTRUCTION CO INC	Construction	8,730,985	8,338,962	107/108
GAFFNEY BENNETT PUBLIC RELATIONS	Consulting	77,723		
GANICK OBRIEN & SARIN	Legal	50,659		
GE GRID SOLUTIONS LLC	Construction	87,308	86,847	107/108
GENBRIGHT LLC	CL&M	336,207		
GENERAL CABLE INDUSTRIES INC	Maintenance	36,696	36,696	107
GEODIGITAL INTERNATIONAL	Consulting	71,804		
GIL-DEN INC	Maintenance	76,573	73,256	107/108
GLOBAL ENERGY SERVICES, INC	Construction	9,460,471	370,498	107
GLOBAL ENERGY SOLUTIONS	Operations	96,577		
GLOBAL RENTAL COMPANY INC	Operations	311,235	311,235	107
GLYNN ELECTRIC	CL&M	607,104		
GRAINGER	Construction	563,493	256,550	107
GRATTAN LINE CONSTRUCTION CORP	Construction	813,915		
GRAYBAR ELECTRIC CORP INC	Operations	151,732	72,890	107
GREEN ENERGY SOLUTIONS INC	CL&M	530,825		
GREEN MOUNTAIN COMMUNICATIONS INC	IT Services	249,058	39,383	107
GREENJACKET INC	IT Services	103,300	103,300	107/108
GREGORY ELECTRIC COMPANY INC	CL&M	725,724		
GRIDEDGE NETWORKS INC	IT Services	352,873	303,493	107/108
GROSOLAR	Operations	9,866,558	9,866,558	107
GZA GEOENVIRONMENTAL INC	Environmental	283,432	86,505	107/108
HALEY & ALDRICH INC	Engineering	77,439	77,439	107
HARLAN ELECTRIC CO	Construction	14,148,399	13,619,915	107
HARRY R FELDMAN INC	Engineering	391,034	391,030	107
HAVERFIELD AVIATION INC	Operations	355,651	133,259	107
HDR ENGINEERING INC	Engineering	123,234	123,234	107
HEI ENERGY LLC	CL&M	71,244		
HENKELS & MCCOY INC	Consulting	146,455	146,455	107/108
HI VOLT LINE CONSTRUCTION & MAINTENANCE INC	Construction	265,009		
HICO AMERICA SALES & TECH	Construction	532,135	532,135	107
HINDS & COON COMPANY	Maintenance	54,569	33,964	107/108
HINSDALE POLICE DEPARTMENT	Operations	31,039	1,772	107/108
HITACHI T&D SOLUTIONS INC	Operations	220,157		
HOLMESTEAD NURSERY INC	Vegetation	61,491	24,375	107/108
HORIZON SOLUTIONS LLC	CL&M	1,146,720		
HOWARD INDUSTRIES INC	Maintenance	36,934	30,614	107/108
HOYA VISION CARE	Operations	87,396		
HYDRON INC	Maintenance	36,627	20,666	107
I B ABEL INC	Construction	5,734,830	3,470,440	107/108
I C REED & SONS INC	Operations	976,806		
I C SYSTEM INC	Financial	41,540		
ICE ENERGY HOLDINGS INC	CL&M	90,736		
ICF RESOURCES LLC	IT Services	5,289,033		
ILLUME ADVISING LLC	Consulting	88,492		
INDIANAPOLIS POWER & LIGHT CO	CL&M	592,490		
INDUSTRIAL COMMUNICATIONS	IT Services	54,965	44,769	107/108
INDUSTRIAL ECONOMICS, INC.	Consulting	43,333		
INDUSTRIAL PROTECTION PRODUCTS INC	Operations	74,392		
INDUSTRIAL TOWER & WIRELESS LLC	IT Services	128,201		
INFOSYS TECHNOLOGIES LIMITED	IT Services	52,752		
INSIGHT DIRECT USA INC	IT Services	27,887	6,244	107/108
ITRON INC	Construction	735,752	666,756	107
J & M BROWN COMPANY INC	Construction	32,993	32,993	107/108

Year 2018 Total payments of greater than $25,000 but less than 5% of total	Predominant nature of services performed	Total Paid	Amount charged to plant accounts	Plant account charged
J C EHRLICH CO INC	Facilities	62,100	56,795	107/108
J CALNAN & ASSOCIATES	Construction	463,285	463,285	107/108
J.C. CANNISTRARO LLC	Construction	46,005	46,005	107
JAMES A KILEY CO	Operations	58,153	58,153	107
JCR CONSTRUCTION CO INC	Construction	1,019,691	32,476	107/108
JEFFREY S HAMILTON TREE & LANDSCAPE INC	Vegetation	1,418,683	43,462	107/108
JF2 LLC	Construction	57,996		
JH EGGER CO INC	Construction	400,023	341,783	107/108
JK ENERGY SOLUTIONS LLC	Consulting	1,084,712		
JOE BRIGHAM INC	Operations	68,948		
JOSEPH BOTTI CO	Construction	3,044,259	2,685,166	107/108
JP MORGAN CHASE BANK	Financial	4,268,189	430,445	107/108
KARLS SITE WORK INC	Construction	579,991	477,757	107/108
KEEGAN WERLIN LLP	Legal	4,243,950	2,196,020	107/108
KELLIHER SAMETS LTD	CL&M	1,233,760		
KEMA INC	CL&M	2,021,230		
KENSINGTON WELDING & TRAILER	Construction	74,639	74,639	107
KEOLIS COMMUTER SERVICES, LLC	Transportation	95,595	89,290	107/108
KLEENRITE SERVICES	Operations	88,267		
KOBO UTILITY CONSTRUCTION CORP	Construction	91,026	62,795	107
KTI UTILITY CONSTRUCTION &	Construction	50,925		
KUBRA ARIZONA INC	Operations	31,224		
LAWRENCE LYNCH CORP.	Construction	4,360,995	4,203,060	107
LEFTFIELD LLC	Consulting	35,899		
LEIDOS ENGINEERING LLC	Engineering	771,811		
LEWIS TREE SERVICE INC	Vegetation	11,464,752	1,426,849	107
LIGHTING RETROFIT SERVICES INC	Engineering	36,299		
LIGHTSHIP ENGINEERING, LLC	Engineering	99,217	89,105	107
LIME ENERGY	CL&M	5,432,970		
LINEBROOK SERVICES LLC	Vegetation	98,518		
LOCKHEED MARTIN SERVICES INC	CL&M	728,780		
LOGIC SUPPLY INC	Operations	25,475	25,475	107
LONDON ECONOMICS INTERNATIONAL	Consulting	243,990	243,990	107
LONGCHAMP ELECTRIC	CL&M	222,293		
LOUREIRO ENGINEERING ASSOC INC	Engineering	35,291		
LUCAS TREE EXPERTS	Vegetation	262,864	23,435	107
M J ELECTRIC LLC	Maintenance	5,124,742	4,403,087	107/108
MAC PRODUCTS INC	IT Services	207,188	207,188	107/108
MARR SCAFFOLDING COMPANY INC	Construction	110,099	99,153	107/108
MASS BAY ELECTRICAL CORP	Construction	954,487	196,408	107/108
MASSACHUSETTS STATE POLICE	Operations	384,372	179,916	107/108
MASSACHUSETTS TECHNOLOGY PARK	CL&M	1,772,483		
MATRIX NAC	Construction	89,806		
MAVERICK CONSTRUCTION CORP	Construction	2,217,008	520,472	107/108
MC PHEE ELECTRIC	CL&M	80,977		
MCCOURT CONSTRUCTION	Construction	9,594,598	9,491,323	107/108
MCDONOUGH ELECTRIC CONST CO	Construction	74,439		
MCLAUGHLIN CHEVROLET INC	Construction	2,423,111	2,423,111	107
MCPHEE ELECTRIC LTD LLC	Construction	456,091	452,534	107/108
MDR CONSTRUCTION INC	Construction	127,540		
MERRIMAC INDUSTRIAL SALES, INC	Operations	34,500	34,500	107
METSCO ENERGY SOLUTIONS INC	Consulting	57,300	57,300	107
MICHELS POWER	CL&M	1,813,094		
MIDDLESEX CORP	Consulting	8,431,901	8,098,014	107/108
MIDWEST POWERLINE INC	CL&M	186,783		
MILONE & MACBROOM	Construction	57,340	45,520	107
MIRRA CO INC	Construction	3,511,503	2,810,488	107/108
MISTY HILL LANDSCAPE DESI	Facilities	68,388	49,882	107/108
MITSUBISHI ELEC POWER PROD INC	Construction	11,389,193	11,338,992	107

Year 2018 Total payments of greater than $25,000 but less than 5% of total	Predominant nature of services performed	Total Paid	Amount charged to plant accounts	Plant account charged
MOHAWK LTD	IT Services	163,213	55,815	107
MORAN ENVIRONMENTAL RECOVERY	Environmental	756,009	682,470	107/108
MORGAN BROWN JOY LLP	Legal	221,692		
MTV SOLUTIONS INC	Operations	4,384,844		
NAIR & LEVIN PC	CL&M	32,444		
NATIONAL GRID	CL&M	126,458		
NATIONAL RESOURCE MGMT INC	Consulting	27,664		
NAVIGANT	Staffing	1,450,599		
NE ELECTRIC TRANSMISSION CORP	Operations	31,931		
NETWORK MAPPING INC	IT Services	28,000	28,000	107
NEW ENGLAND CP INC	Operations	26,350		
NEW ENGLAND HYDRO TRANSMISSION	Operations	1,539,261		
NEW ENGLAND TRAFFIC CONTR SVCS	Operations	25,826		
NEW HAMPSHIRE ELECTRIC CO OP	CL&M	106,302		
NITSCH ENGINEERING, INC	Engineering	178,283	101,970	107/108
NMR GROUP INC	CL&M	1,690,587		
NOREL SERVICE CO INC	Maintenance	61,584	61,584	107/108
NORMANDEAU ASSOCIATES INC	Environmental	41,666	38,476	107/108
NORTH AMERICAN SUBSTATION SVCS INC	Maintenance	120,106	120,106	107/108
NORTHEAST GAS ASSOCIATION	Operations	28,093		
NORTHERN TREE SERVICE INC	Vegetation	6,044,475	1,435,372	107/108
NORTHLINE UTILITIES LLC	CL&M	83,266		
NOVINIUM INC	Construction	416,186	308,982	107/108
NWN CORPORATION	IT Services	192,589	189,965	107
OJS LANDSCAPE EXCAVATION INC	Vegetation	85,518		
OLSEN CONSTRUCTION SERVICES	Construction	3,106,219	3,098,164	107/108
OMICRON ELECTRONICS CORP USA	Maintenance	43,970	43,970	107
ONE SOURCE POWER, LLC	CL&M	3,034,530		
ONLINE COLLECTIONS	Financial	36,245		
OPINION DYNAMICS CORPORATION	Consulting	55,579		
ORACLE AMERICA INC	CL&M	2,790,672		
ORIONMAGNETICS LLC	Operations	61,350	3,750	107/108
OSMOSE UTILITIES SERVICES INC	CL&M	1,160,676		
OWENS GENERAL CONTRACTOR INC	Construction	120,581	103,975	107/108
OXBOW ASSOCIATES INC	Environmental	65,955	63,455	107
PAR ELECTRICAL CONTRACTORS INC	Construction	20,087,504	14,661,574	107/108
PARK RESTAURANT MANAGEMENT LLC	Operations	506,869		
PASEK LOCK CORPORATION	Maintenance	43,442	32,881	107/108
PASQUARIELLO ELECTRIC CORP	CL&M	61,860		
PENNSYLVANIA TRANSFORMER	Operations	36,236	36,236	107
PERFORMANCE SYSTEMS DEVELOPMEN	Consulting	173,766		
PFT TECHNOLOGY LLC	IT Services	609,230		
PHILLIPS BROTHERS ELECTRIC CONT INC	Construction	25,381		
PHOENIX COMMUNICATIONS INC	Construction	434,212	388,036	107/108
PHOENIX SOIL	Environmental	54,110	54,110	107
PLANET FORWARD ENERGY SOLUTIONS LLC	Consulting	182,160	182,160	107
PLM ELECTRIC POWER ENGINEERING	Construction	553,726	553,726	107/108
PLUS RELOCATION SERVICES INC	Operations	59,646		
PMA CONSULTANTS LLC	Staffing	1,496,198	1,466,485	107/108
POWER DELIVERY ALLIANCE INC	CL&M	2,087,194		
POWER DESIGN & INSTALLATION GROUP LLC	Engineering	43,786	43,786	107
POWER ENGINEERS CONSULTING INC	Construction	1,069,213	1,069,213	107
POWER GRID ENGINEERING LLC	Engineering	189,156	189,156	107/108
POWER LINE CONTRACTORS INC	Construction	345,611		
POWER SURVEY LLC	Consulting	225,000		
PREFERRED COMMUNICATIONS	Operations	60,487		
PSC GROUP INC	IT Services	241,530	193,224	107/108
PUBLIC ARCHAEOLOGY	Environmental	155,888	155,888	107
QUANTA TECHNOLOGY LLC	IT Services	248,921		

Year 2018 Total payments of greater than $25,000 but less than 5% of total	Predominant nature of services performed	Total Paid	Amount charged to plant accounts	Plant account charged
R G VANDERWEIL ENGINEERS INC	Engineering	1,216,277	1,195,718	107/108
RANDSTAD US LP	Operations	2,662,202	668,346	107/108
RCM TECHNOLOGIES INC	IT Services	185,538	185,538	107
REAL POWER INC	CL&M	56,051	56,051	107
REALTIME UTILITY ENGINEERS INC	Engineering	41,062	41,062	107
RED THREAD SPACES LLC	Consulting	314,159	314,159	107/108
REILLY ELECTRICAL CONTRACTORS INC	Construction	176,436		
RENAUD HVAC & CONTROLS INC	Construction	39,875	39,875	107/108
REPUBLIC SERVICES	CL&M	64,166	37,400	107/108
RETRO COOL ENERGY	Operations	47,804		
RHINO LININGS OF SALEM N H	Construction	120,950	120,950	107/108
RICHARDSON WAYLAND ELECTRIC CO LLC	Operations	213,321		
RIGGS DISTLER & COMPANY INC	Operations	1,166,443	545,778	107/108
RILEY BROTHERS INC	Operations	8,791,154	7,536,453	107/108
RISE ENGINEERING	Engineering	5,700,966		
RIVER ENERGY CONSULTANTS	Consulting	968,394		
RLC ENGINEERING LLC	Engineering	1,105,070	944,332	107/108
ROBERT J DEVEREAUX CORP	Operations	32,373	6,997	
ROPES & GRAY	Legal	90,876		
RTM MANUFACTURING LLC	IT Services	83,308	83,308	107/108
RUI CREDIT SERVICES	Financial	336,373		
S & C ELECTRIC CO	Construction	162,644	148,921	107/108
SABRE TOWERS & POLES	Operations	1,237,764		107/108
SABRE TUBULAR STRUCTURES	IT Services	517,416		107
SAK ENVIRONMENTAL LLC	Environmental	65,879	65,879	107
SARGENT ELECTRIC COMPANY	CL&M	1,257,323		
SCHMIDT EQUIPMENT INC	Construction	125,056	125,056	107/108
SCHNEIDER ELECTRIC USA INC	Construction	106,008	106,008	107
SCIOLI ELECTRICAL SERVICES	CL&M	27,600	11,400	107/108
SECURITYWORKS, INC	Security	147,670	135,984	107/108
SENSIBLE ERGONOMIC SOLUTIONS	Operations	92,045		
SGC ENGINEERING LLC	Engineering	213,512	213,512	107/108
SHAUGHNESSY & AHERN CO INC	Construction	391,830	374,739	107
SHEERIN CONSTRUCTION CORP	Construction	7,639,159	4,698,384	107/108
SHERMAN CRANE SERVICE INC	Construction	387,310	387,310	107/108
SIEMENS INDUSTRY INC	Construction	606,462	106,367	107
SLAM COLLABORATIVE	Construction	27,930	27,930	107/108
SMITH MOUNTAIN INVESTMENTS LLC	Operations	1,169,392	199,476	107/108
SOUTHERN STATES LLC	Construction	46,707	45,783	107
SOUTHWICK POLICE DEPARTMENT	Operations	58,130		
SPARKS ENERGY INC	Construction	2,246,306		
SPECIALIZED ROOFING CO	Construction	59,230	44,730	107
STADELMANN ELECTRIC	Construction	34,504	34,504	107/108
STANDARD ELECTRIC INC	Construction	205,355	189,601	107
STANDARD REGISTER COMPANY	Construction	63,281		
STANLEY TREE SERVICE INC	Vegetation	4,387,232	1,099,465	107/108
STANTEC CONSULTING SERVICES INC	Staffing	81,752	80,313	107/108
STATE ELECTRIC CORP	Construction	2,488,051	378,693	107/108
STEM INC	Operations	500,000		
STONEHAM FORD	Construction	156,686	156,686	107/108
SUMMIT HANDLING SYSTEMS INC	Construction	304,066	304,066	107
SUMMIT TOYOTA LIFT	Construction	30,454	30,454	107
SUNBELT RENTALS INC	Operations	7,463,082	4,735,569	107/108
SUNMERGE SYSTEMS INC	Construction	82,879		
SURPLEC INC	Operations	118,320	118,320	107/108
SURVEYING & MAPPING CONSULTANT	Construction	103,419	103,419	107/108
SYNAPSE ENERGY ECONOMICS INC	Consulting	81,492		
SYNCWORKS	IT Services	28,300	28,300	107
SYSTEMS MANAGEMENT PLANNING INC	IT Services	34,562	34,562	107

Year 2018 Total payments of greater than $25,000 but less than 5% of total	Predominant nature of services performed	Total Paid	Amount charged to plant accounts	Plant account charged
T&T LINE CONSTRUCTION LTD	Construction	501,287		
TABORS CARAMANIS RUDKEVICH INC	Construction	847,954		
TATA AMERICA INTERNATIONAL CORP	Consulting	345,146		
TCI OF NY LLC	Consulting	112,773	112,773	107
TECHNICAL CONSTR SERV INC	Construction	214,608	19,683	107/108
TENNETT TREE SERVICE INC	Vegetation	37,136		
TERRACON CONSULTANTS INC	Construction	238,553	238,553	107
THE BOSTON GLOBE	CL&M	163,665		
THE CADMUS GROUP INC	Construction	1,307,077		
THE CASUAL GOURMET INC	Construction	377,450		
THE ERGONOMIC GROUP	IT Services	1,298,586	1,246,768	107/108
THE MIDDLESEX CORPORATION	Construction	3,583,972	3,583,972	107
THIELSCH ENGINEERING INC	Engineering	28,986		
THOMAS P RYLAND COMPANY INC	Vegetation	38,851		
THORNTON TOMASETTI INC	Construction	124,045	124,045	107
THREE PHASE LINE CONST INC	Construction	5,162,211	3,811,183	107
TIGHE & BOND CONS ENG	Engineering	1,968,944	1,514,151	107/108
TOWER RESOURCE MANAGEMENT	IT Services	38,165	38,165	107/108
TOWN OF ACTON	Operations	83,079	50,524	107/108
TOWN OF AGAWAM	Operations	70,645	8,694	107/108
TOWN OF AMHERST	Operations	70,200	3,046	107/108
TOWN OF ARLINGTON	Operations	52,479	26,170	107/108
TOWN OF BARNSTABLE	Operations	109,809	46,561	107/108
TOWN OF BEDFORD	Operations	57,829	42,134	107/108
TOWN OF BILLERICA	Operations	97,604	67,699	107/108
TOWN OF BROOKLINE	Operations	183,080	127,886	107/108
TOWN OF BURLINGTON	Operations	124,383	58,494	107/108
TOWN OF CANTON OR NSTAR	Operations	53,836	26,074	107/108
TOWN OF CARVER	Operations	121,663	78,355	107/108
TOWN OF CUMMINGTON	Operations	26,821		
TOWN OF DALTON	Operations	54,905	7,055	107/108
TOWN OF DARTMOUTH	Operations	92,568	52,999	107/108
TOWN OF DEDHAM	Operations	55,168	26,711	107/108
TOWN OF DEERFIELD	Operations	93,795	7,409	107/108
TOWN OF DENNIS	Operations	39,415	22,687	107/108
TOWN OF DUXBURY	Operations	39,409	15,948	107/108
TOWN OF FALMOUTH	Operations	53,258	25,849	107/108
TOWN OF FRAMINGHAM	Operations	196,935	116,857	107/108
TOWN OF GREENFIELD	Operations	36,169	3,556	107/108
TOWN OF HARWICH	Operations	31,188	13,401	107/108
TOWN OF HOLLISTON	Operations	35,883	14,262	107/108
TOWN OF HOPKINTON	Operations	39,311	12,774	107/108
TOWN OF LEE	Operations	256,378		
TOWN OF LEXINGTON	Operations	136,300	94,613	107/108
TOWN OF LINCOLN	Operations	39,310	27,339	107/108
TOWN OF LUDLOW	Operations	65,823	902	107/108
TOWN OF MARSHFIELD	Operations	133,196	73,101	107/108
TOWN OF MASHPEE	Operations	36,373	12,745	107/108
TOWN OF MATTAPOISETT	Operations	38,447	16,979	107/108
TOWN OF MILLIS	Operations	47,993	24,260	107/108
TOWN OF MILTON	Operations	62,162	36,307	107/108
TOWN OF MONTAGUE	Operations	246,177	4,704	107/108
TOWN OF NATICK	Operations	39,272	17,712	107/108
TOWN OF NEEDHAM	Operations	99,015	50,096	107/108
TOWN OF NORFOLK	Operations	34,322	15,998	107/108
TOWN OF OTIS	Operations	218,219		
TOWN OF PLYMOUTH	Operations	111,853	78,554	107/108
TOWN OF PLYMPTON	Operations	40,741	7,553	107/108
TOWN OF ROCHESTER	Operations	29,858	22,004	107/108

Year 2018 Total payments of greater than $25,000 but less than 5% of total	Predominant nature of services performed	Total Paid	Amount charged to plant accounts	Plant account charged
TOWN OF SANDWICH	Operations	29,015	20,360	107/108
TOWN OF SHERBORN	Operations	25,011	15,449	107/108
TOWN OF SOUTHAMPTON	Operations	64,566	454	107/108
TOWN OF STONEHAM	Operations	57,084	33,278	107/108
TOWN OF SUDBURY	Operations	70,659	27,024	107/108
TOWN OF WALPOLE	Operations	81,518	45,349	107/108
TOWN OF WAREHAM	Operations	63,663	32,344	107/108
TOWN OF WATERTOWN	Operations	115,688	62,606	107/108
TOWN OF WAYLAND	Operations	30,080	15,168	107/108
TOWN OF WEST SPRINGFIELD	Operations	58,182	4,411	107/108
TOWN OF WESTON	Operations	52,951	27,742	107/108
TOWN OF WESTPORT	Operations	25,004	12,758	107/108
TOWN OF WHATELY	Operations	30,741	1,260	107/108
TOWN OF WINCHESTER	Operations	87,482	36,246	107/108
TOWN OF YARMOUTH	Operations	33,422	15,763	107/108
TRC ENGINEERS LLC	Environmental	1,766,599	1,300,409	107/108
TRC LOCKBOX	CL&M	784,269	755,287	107/108
TREE TECHNOLOGY & LANDSCAPE CO INC	Vegetation	1,684,800	8,422	107
TREGO INC	Operations	28,958	28,958	107/108
TREMCO	Maintenance	35,173	35,173	107
TRENCH LIMITED	Construction	110,065	110,065	107/108
TRINITY MEYER UTILITY STRUCTURES LLC	Construction	1,276,849	1,276,849	107/108
TRIPI ENGINEERING SERVICES LLC	Engineering	46,080	46,080	107
TYNDALE COMPANY INC	Environmental	1,356,876		
U S SECURITY ASSOCIATES INC	Security	103,688	75,344	107/108
UNDERGROUND SYSTEMS INC	Maintenance	637,774	498,404	107
UNIFIRST CORP	Operations	30,090		
UNITED CIVIL INC	Construction	991,924	793,539	107
UNITED RENTALS INC	Construction	658,448	603,859	107/108
UNITED SITE SERVICES INC	Operations	34,683	19,678	107/108
UNITIL	CL&M	204,264		
UNIVERSAL WILDE, INC.	Financial	221,690		
USIC LOCATING SERVICES LLC	Operations	880,678		
UTEC CONSTRUCTORS LLC	Construction	970,688	970,688	107
UTILE INC	Engineering	49,283	49,283	107/108
UTILITY CONSTRUCTION MGMT LLC	Construction	28,188		
UTILITY SERVICE & ASSISTANCE	Operations	416,918		
VALIANT ENERGY SERVICE LLC	Construction	175,850		
VANASSE HANGEN BRUSTLIN INC	Construction	2,739,853	2,728,096	107
VEGETATION CONTROL SERVICE INC	Vegetation	223,993		
VEOLIA ES TECHNICAL SOLUTIONS LLC	IT Services	96,275		
VERIZON	Operations	136,864		
VERMONT ELECTRIC COOPERATIVE INC	Construction	110,649		
VHB INC	Construction	995,181	995,181	107/108
VISI-FLASH RENTALS EASTERN INC	Operations	80,431	78,986	107/108
VITTIGLIO CONSTRUCTION CORP	Construction	45,240	43,490	107
W A CHESTER LLC	Construction	2,839,532	1,884,750	107
W L FRENCH EXCAVATING CORP	Construction	395,089	395,089	107
WAGNER TECHNICAL SERVICES INC	Engineering	168,462	117,374	107
WARREN ENERGY ENGINEERING LLC	Engineering	32,571		
WAS BROTHERS CONSTRUCTION INC	Construction	788,291	736,112	107/108
WATKINS STRATEGIES LLC	Construction	242,223	238,315	107/108
WAUKESHA ELECTRIC SYSTEM INC	Construction	76,350	76,350	107/108
WB MASON CO INC	Construction	581,681	406,121	107
WEST INTERACTIVE SERVICES CORPORATION INC	Construction	118,472		
WESTON & SAMPSON ENGINEERS INC	Engineering	513,684	233,822	107
WESTWOOD POLICE DEPARTMENT	Operations	56,273	28,561	107/108
WHITES OF WESTPORT	Operations	273,386		
WILLIAMS SCOTSMAN INC	Maintenance	69,790	69,422	107/108

Year 2018 Total payments of greater than $25,000 but less than 5% of total	Predominant nature of services performed	Total Paid	Amount charged to plant accounts	Plant account charged
WINKLER ENERGY CONSULTING LLC	Consulting	33,163		
WITCH ENTERPRISES	Construction	2,150,766	1,656,943	107/108
WOODS HOLE STEAMSHIP AUTH	Operations	53,204		
WORLD ENERGY EFFICIENCY SERVICES LLC	CL&M	4,220,609		
WUNDERLICH MALEC SERVICES	Construction	10,381,022	10,381,022	107/108
Total payments greater than $25,000, less than 5% of total		601,378,621	311,511,133	
Total from S18-A		41,770,863	-	
Total payments less than $25,000 of total		3,984,967	1,658,692	
Grand Total		$ 647,134,451	$ 313,169,825	

Annual report of NSTAR Electric Company Year ended December 31, 2018

DEPOSITS AND COLLATERAL

1. Statement of money and the value of any collateral held as guaranty for the payment of charges pursuant to Massachusetts General Laws. Chapter 164, Section 128.

Line No.	Name of City or Town	Amount	Line No.	Name of City or Town	Amount
1	Acton	$ 57,030	41	Mattapoisett	4,655
2	Acushnet	3,130	42	Maynard	14,173
3	Arlington	38,583	43	Medfield	12,124
4	Ashland	12,409	44	Medway	21,495
5	Assonet	11,515	45	Millis	9,025
6	Bedford	54,657	46	Milton	14,009
7	Bellingham	8,903	47	Natick	63,305
8	Boston	2,182,344	48	Needham	66,302
9	Bourne	32,669	49	Newton	279,670
10	Brewster	6,940	50	New Bedford	178,008
11	Brookline	63,356	51	Norfolk	8,948
12	Burlington	277,120	52	Oak Bluffs	13,665
13	Cambridge	118,415	53	Orleans	15,339
14	Canton	272,829	54	Pembroke	222
15	Carlisle	315	55	Plymouth	99,044
16	Carver	15,553	56	Plympton	4,874
17	Chatham	11,198	57	Provincetown	21,697
18	Chelsea	97,882	58	Rochester	14,367
19	Chilmark	250	59	Sandwich	11,106
20	Dartmouth	33,702	60	Scituate	600
21	Dedham	38,634	61	Sharon	4,334
22	Dennis	30,661	62	Somerville	160,926
23	Dover	2,367	63	Stoneham	38,402
24	Duxbury	9,972	64	Sudbury	10,583
25	Eastham	42,067	65	Truro	7,794
26	Edgartown	19,253	66	Vineyard Haven	5,504
27	Fairhaven	24,847	67	Walpole	40,021
28	Falmouth	38,320	68	Waltham	223,563
29	Framingham	161,339	69	Wareham	65,369
30	Harwich	16,940	70	Watertown	148,701
31	Holliston	24,386	71	Wayland	6,731
32	Hopkinton	16,585	72	Wellfleet	7,880
33	Hyannis	118,415	73	Weston	2,320
34	Kingston	33,548	74	Westport	9,195
35	Lakeville	400	75	Westwood	8,869
36	Lexington	65,200	76	West Tisbury	3,500
37	Lincoln	58,760	77	Winchester	13,607
38	Marion	3,039	78	Woburn	174,081
39	Marshfield	39,713	79	Yarmouth	40,640
40	Mashpee	12,020	80	Western MA	2,122,663
				Total	$ 8,002,577

Note: Except for the above amount, the Company does not presently hold any collateral from its customers as a guaranty for the payment of charges which is capable of valuation within the meaning of M.G.L. Chapter 164; Section 128. The Company does in certain instances accept surety bonds and/or second mortgages as guaranties of payment. The value of such collateral cannot be ascertained however, since the Company holds nothing but a commitment to make payment in the event of a customer's default up to the limit of the instruments.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	April 12, 2019	December 31, 2018

THIS RETURN (THE FERC FORM NO.1 AND THE MASSACHUSETTS SUPPLEMENT)
IS SIGNED UNDER THE PENALTIES OF PERJURY

.....	Jay S. Buth	Vice President, Controller and Chief Accounting Officer
.....	John M. Moreira	Senior Vice President - Finance and Regulatory and Treasurer

Directors:

.....	Gregory B. Butler	Director
.....	James J. Judge	Director
.....	Philip J. Lembo	Director
.....	Werner J. Schweiger	Director

SIGNATURE OF ABOVE PARTIES MUST BE PROPERLY SWORN TO

State of: Connecticut

County of: Hartford

City of: Berlin

April 12, 2019

Then personally appeared Jay S. Buth and made oath to the truth of the foregoing statement by him subscribed according to his best knowledge and belief.

Joyce Chandler Notary Public

My commission expires: 11/30/2023

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	April 12, 2019	December 31, 2018

THIS RETURN (THE FERC FORM NO.1 AND THE MASSACHUSETTS SUPPLEMENT)
IS SIGNED UNDER THE PENALTIES OF PERJURY

	Jay S. Buth	Vice President, Controller and Chief Accounting Officer
John M. Moreira	John M. Moreira	Senior Vice President - Finance and Regulatory and Treasurer

Directors:

Gregory B. Butler	Director
James J. Judge	Director
Philip J. Lembo	Director
Werner J. Schweiger	Director

SIGNATURE OF ABOVE PARTIES MUST BE PROPERLY SWORN TO

State of: Massachusetts

County of: Norfolk

City of: Westwood

April 12, 2019

Then personally appeared John M. Moreira and made oath to the truth of the foregoing statement by him subscribed according to his best knowledge and belief.

Diane Citrone Notary Public

My commission expires: 2·10·23

DIANE CITRONE
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
February 10, 2023

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	April 12, 2019	December 31, 2018

THIS RETURN (THE FERC FORM NO.1 AND THE MASSACHUSETTS SUPPLEMENT)
IS SIGNED UNDER THE PENALTIES OF PERJURY

.....	Jay S. Buth	Vice President, Controller and Chief Accounting Officer
.....	John M. Moreira	Senior Vice President - Finance and Regulatory and Treasurer

Directors:

.....	Gregory B. Butler	Director
.....	James J. Judge	Director
.....	Philip J. Lembo	Director
.....	Werner J. Schweiger	Director

SIGNATURE OF ABOVE PARTIES MUST BE PROPERLY SWORN TO

State of: Connecticut

County of: Hartford

City of: Hartford

April 12, 2019

Then personally appeared Gregory B. Butler and made oath to the truth of the foregoing statement by him subscribed according to his best knowledge and belief.

Kathy L. Schmidt Notary Public

My commission expires: 9-30-19

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	April 12, 2019	December 31, 2018

THIS RETURN (THE FERC FORM NO.1 AND THE MASSACHUSETTS SUPPLEMENT)
IS SIGNED UNDER THE PENALTIES OF PERJURY

	Jay S. Buth	Vice President, Controller and Chief Accounting Officer
	John M. Moreira	Senior Vice President - Finance and Regulatory and Treasurer

Directors:

	Gregory B. Butler	Director
James J. Judge	James J. Judge	Director
	Philip J. Lembo	Director
	Werner J. Schweiger	Director

SIGNATURE OF ABOVE PARTIES MUST BE PROPERLY SWORN TO

State of: MASSACHUSETTS

County of: SUFFOLK

City of: BOSTON

April 12, 2019

Then personally appeared JAMES J. JUDGE and made oath to the truth of the foregoing statement by him subscribed according to his best knowledge and belief.

Barbara J Murphy Notary Public

My commission expires: APRIL 11, 2025

BARBARA J MURPHY
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
April 11, 2025

BARBARA J MURPHY
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
2025

BARBARA J MURPHY
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
April 11, 2025

BARBARA J MURPHY
Notary Public
COMMONWEALTH OF MASSACHUSETTS
Expires

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	April 12, 2019	December 31, 2018

THIS RETURN (THE FERC FORM NO.1 AND THE MASSACHUSETTS SUPPLEMENT)
IS SIGNED UNDER THE PENALTIES OF PERJURY

Jay S. Buth	Vice President, Controller and Chief Accounting Officer
John M. Moreira	Senior Vice President - Finance and Regulatory and Treasurer

Directors:

Gregory B. Butler	Director
James J. Judge	Director
Philip J. Lembo	Director
Werner J. Schweiger	Director

SIGNATURE OF ABOVE PARTIES MUST BE PROPERLY SWORN TO

State of: Massachusetts

County of: Norfolk

City of: Westwood

April 12, 2019

Then personally appeared Philip J. Lembo and made oath to the truth of the foregoing statement by him subscribed according to his best knowledge and belief.

Dana M. Fennelly Notary Public

My commission expires: December 14 2023

DANA M. FENNELLY
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
December 14, 2023

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
NSTAR Electric Company	(1) [X] An Original (2) [ ] A Resubmission	April 12, 2019	December 31, 2018

THIS RETURN (THE FERC FORM NO.1 AND THE MASSACHUSETTS SUPPLEMENT)
IS SIGNED UNDER THE PENALTIES OF PERJURY

	Jay S. Buth	Vice President, Controller and Chief Accounting Officer
	John M. Moreira	Senior Vice President - Finance and Regulatory and Treasurer

Directors:

	Gregory B. Butler	Director
	James J. Judge	Director
	Philip J. Lembo	Director
	Werner J. Schweiger	Director

SIGNATURE OF ABOVE PARTIES MUST BE PROPERLY SWORN TO

State of: Connecticut

County of: Hartford

City of: Berlin

April 12, 2019

Then personally appeared Werner Schweiger and made oath to the truth of the foregoing statement by him subscribed according to his best knowledge and belief.

Lynn M Mancini Notary Public

My commission expires: 2/28/2022

EXTRACTS FROM THE GENERAL LAWS.

CHAPTER 164.

Section 2. In construing sections*** seventy-four to eighty-three inclusive,*** unless this context otherwise requires, the terms "corporation", "gas company" and "electric company" shall include all persons, firms, associations and private corporations which own or operate works or a distributing plant for the manufacture and sale or distribution and sale of gas for heating and illuminating purposes, or of electricity, within the commonwealth.***

GENERAL DUTIES OF DEPARTMENT

SECTION 76. The department shall have the general supervision of all gas and electric companies and shall make all necessary examination and inquiries and keep itself informed as to the condition of the respective properties owned by such corporation and the manner in which they are conducted with reference to the safety and convenience of the public and as to their compliance with the provisions of law and the orders, directions and requirements of the department.

FORM OF BOOKS AND ACCOUNTS PRESCRIBED.

SECTION 81. Gas and electric companies or persons engaged in the manufacture and sale or distribution of gas or electricity shall keep their books and accounts in a form to be prescribed by the department, and the accounts shall be closed annually, so that a balance sheet can be taken therefrom. Manufacturing companies in which the manufacture of gas or electricity is a minor portion of their business shall be required to keep accounts of the expenses and income of their gas or electric business only.

FORM OF STATION RECORDS PRESCRIBED.

SECTION 82. Gas and electric companies and manufacturing companies or persons engaged in the manufactu or sale of gas or electricity shall keep such records of their work at their manufacturing station, and in respect to their distributing plant, and in such forms as the department may from time to time require.

FORM OF ANNUAL RETURNS PRESCRIBED.

SECTION 83. Gas and electric companies and manufacturing companies and persons engaged in the manufacl and sale or distribution and sale of gas or electricity shall annually, on or before such date as the department fixes, make to the department, in the form prescribed by it, a return for the year ending on such date as the department may from time to time require, signed and sworn to by the president or vice-president, and treasurer or assistant treasurer, and a majority of the directors, of the amount of their authorized capital, their indebtedness and financial condition, on the said date, their income and expenses during the preceding year, their dividends paid and declared, a list of the names of all their salaried officers and the amount of the salary paid to each, and the balance sheet of their accounts as of said date. Such companies and persons shall at all times, upon request, furnish any information required by the department of its duly authorized employees relative to their condition, management and operation, and shall comply with all lawful orders of the department: but manufacturing companies in which the manufacture and sale of gas or electricity is a minor portion of their business shall be required to include in their annual returns the income and expenses and other data relative to their gas and electric business only.

PENALTY FOR FAILURE TO MAKE RETURN.

SECTION 84. Each such gas or electric company or manufacturing company or person neglecting to make the annual return required by the preceding section shall, for the first fifteen days or portion thereof during which such neglect continues, forfeit five dollars a day: for the second fifteen days or any portion thereof, ten dollars a day: and for each day thereafter not more than fifteen dollars a day. If any such company or person unreasonably refuses or neglects to make such return, it or he shall, in addition thereto, forfeit not more than five hundred dollars. If a return is defective or appears to be erroneous, the department shall notify the company or person to amend it within fifteen days. A company or person neglecting to amend said return within the time specified in the notice, when notified to do so, shall forfeit fifteen dollars for each day during which such neglect continues. All forfeitures incurred under this section may be recovered by an information in equity brought in the supreme judicial court by the attorney-general, at the relation of the department, and when so recovered shall be paid to the commonwealth.

CHAPTER 26 B

PENALTIES FOR MAKING FALSE REPORT.

SECTION 6. Except as provided in sections forty-eight and forty-nine of chapter one hundred and fifty-five, whoever shall willfully make false report to the department of public utilities, the department of public works, the department of banking and insurance, or the commissioner of corporations and taxation, or who, before any such department or commissioner, shall testify or affirm falsely to any material fact in any manner wherein an oath or affirmation is required or authorized, or shall make any false entry or memorandum upon any book, report, paper or statement of any company making report to any of the said departments or said commissioner, with intent to deceive the department or commissioner, or any agent appointed to examine the affairs of any such company, or to deceive the stockholders or any officer of any such company, or to injure or defraud any such company, and any person who with like intent aide or abets another in any violation of this section shall be punished by a fine of not more than one thousand dollars or by imprisonment for not more than one year, or both.

Rate	MDPU/MDTE No.	Blocks	Distrib.	Pension Adjust	RAAF Adjust	NMRS Adjust	AGCE Adjust	LTRCA Adjust	SCRA Adjust	Adjusted Distrib	Transition	Transition Rate Adj	Total Transition	Basic Serv Adj	Adjusted Transit	Transm.	DSM	EERF Adjust	Total Energy Efficiency	Renew.	Total Delivery
R-1 (32)	320F	Cust	$ 3.73							$ 3.73											$ 3.73
Annual(BS)		kWh	$ 0.04904	$ (0.00009)	$ 0.00392	$ 0.00704	$ 0.00004	$ 0.00236	$ 0.00056	$ 0.06287	$ 0.00205	$ -	$ 0.00205	$ 0.00191	$ 0.00396	$ 0.02643	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.11015
Annual(CLC)		kWh	$ 0.04904	$ (0.00009)	$ 0.00392	$ 0.00704	$ 0.00004	$ 0.00236	$ 0.00056	$ 0.06287	$ 0.00205	$ -	$ 0.00205	$ 0.00191	$ 0.00396	$ 0.02643	$ 0.00250	$ 0.01859	$ 0.02109	$ 0.00050	$ 0.11485
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
R-1 (66)	320F	Cust	$ 3.73							$ 3.73											$ 3.73
Seasonal(BS)		kWh	$ 0.08326	$ (0.00009)	$ 0.00392	$ 0.00704	$ 0.00004	$ 0.00236	$ 0.00056	$ 0.09709	$ 0.00205	$ -	$ 0.00205	$ 0.00191	$ 0.00396	$ 0.05218	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.17012
Seasonal(CLC)		kWh	$ 0.08326	$ (0.00009)	$ 0.00392	$ 0.00704	$ 0.00004	$ 0.00236	$ 0.00056	$ 0.09709	$ 0.00205	$ -	$ 0.00205	$ 0.00191	$ 0.00396	$ 0.05218	$ 0.00250	$ 0.01859	$ 0.02109	$ 0.00050	$ 0.17482
Seasonal Optional (68)		Minimum payment for billing on annual rate																			$ 10.93
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
R-2 (30)	321G	Cust	$ 3.73							$ 3.73											$ 3.73
Annual(BS)		kWh	$ 0.04904	$ (0.00009)	$ 0.00392	$ 0.00704	$ 0.00004	$ 0.00236	$ 0.00056	$ 0.06287	$ 0.00205	$ -	$ 0.00205	$ 0.00191	$ 0.00396	$ 0.02643	$ 0.00250	$ 0.00083	$ 0.00333	$ 0.00050	$ 0.09709
Annual(CLC)		kWh	$ 0.04904	$ (0.00009)	$ 0.00392	$ 0.00704	$ 0.00004	$ 0.00236	$ 0.00056	$ 0.06287	$ 0.00205	$ -	$ 0.00205	$ 0.00191	$ 0.00396	$ 0.02643	$ 0.00250	$ 0.00148	$ 0.00398	$ 0.00050	$ 0.09774
22.5% discount on total bill																					
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
R-2 (37)	321G	Cust	$ 3.73							$ 3.73											$ 3.73
Seasonal(BS)		kWh	$ 0.08326	$ (0.00009)	$ 0.00392	$ 0.00704	$ 0.00004	$ 0.00236	$ 0.00056	$ 0.09709	$ 0.00205	$ -	$ 0.00205	$ 0.00191	$ 0.00396	$ 0.05218	$ 0.00250	$ 0.00083	$ 0.00333	$ 0.00050	$ 0.15706
Seasonal(CLC)		kWh	$ 0.08326	$ (0.00009)	$ 0.00392	$ 0.00704	$ 0.00004	$ 0.00236	$ 0.00056	$ 0.09709	$ 0.00205	$ -	$ 0.00205	$ 0.00191	$ 0.00396	$ 0.05218	$ 0.00250	$ 0.00148	$ 0.00398	$ 0.00050	$ 0.15771
27.1% discount on total bill																					
Seasonal Optional (38)		Minimum payment for billing on annual rate																			$ 6.39
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
R-3 (86)	322F	Cust	$ 10.03							$ 10.03											$ 10.03
BS		kWh	$ 0.03008	$ (0.00007)	$ 0.00281	$ 0.00506	$ 0.00003	$ 0.00236	$ 0.00040	$ 0.04067	$ 0.00205	$ -	$ 0.00205	$ 0.00137	$ 0.00342	$ 0.02416	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.08514
CLC		kWh	$ 0.03008	$ (0.00007)	$ 0.00281	$ 0.00506	$ 0.00003	$ 0.00236	$ 0.00040	$ 0.04067	$ 0.00205	$ -	$ 0.00205	$ 0.00137	$ 0.00342	$ 0.02416	$ 0.00250	$ 0.01859	$ 0.02109	$ 0.00050	$ 0.08984
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
R-4 (42)	323G	Cust	$ 10.03							$ 10.03											$ 10.03
BS		kWh	$ 0.03008	$ (0.00007)	$ 0.00281	$ 0.00506	$ 0.00003	$ 0.00236	$ 0.00040	$ 0.04067	$ 0.00205	$ -	$ 0.00205	$ 0.00137	$ 0.00342	$ 0.02416	$ 0.00250	$ 0.00083	$ 0.00333	$ 0.00050	$ 0.07208
CLC		kWh	$ 0.03008	$ (0.00007)	$ 0.00281	$ 0.00506	$ 0.00003	$ 0.00236	$ 0.00040	$ 0.04067	$ 0.00205	$ -	$ 0.00205	$ 0.00137	$ 0.00342	$ 0.02416	$ 0.00250	$ 0.00148	$ 0.00398	$ 0.00050	$ 0.07273
19.7% discount on total bill																					
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
R-5 (57)	324F	Cust	$ -							$ -											$ -
Closed(BS)		kWh	$ 0.03131	$ (0.00009)	$ 0.00392	$ 0.00704	$ 0.00004	$ 0.00236	$ 0.00056	$ 0.04514	$ 0.00205	$ -	$ 0.00205	$ 0.00191	$ 0.00396	$ 0.02443	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.09042
Closed(CLC)		kWh	$ 0.03131	$ (0.00009)	$ 0.00392	$ 0.00704	$ 0.00004	$ 0.00236	$ 0.00056	$ 0.04514	$ 0.00205	$ -	$ 0.00205	$ 0.00191	$ 0.00396	$ 0.02443	$ 0.00250	$ 0.01859	$ 0.02109	$ 0.00050	$ 0.09512
Annual		Minimum payment																			$ 1.69
Seasonal (58/59)		Minimum payment for seasonal service during June, July, August and September																			$ 5.12
Seasonal (58/59)		Minimum payment for other months in which electricity is used																			$ 1.69
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
R-6 (TOU) (39/40)	325F	Cust	$ 7.33							$ 7.33											$ 7.33
BS		Pk kWh	$ 0.14549	$ (0.00009)	$ 0.00392	$ 0.00704	$ 0.00004	$ 0.00236	$ 0.00056	$ 0.15932	$ 0.00205	$ -	$ 0.00205	$ 0.00191	$ 0.00396	$ 0.02416	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.20433
BS		Off Pk kWh	$ 0.01102	$ (0.00009)	$ 0.00392	$ 0.00704	$ 0.00004	$ 0.00236	$ 0.00056	$ 0.02485	$ 0.00205	$ -	$ 0.00205	$ 0.00191	$ 0.00396	$ 0.02416	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.06988
CLC		Pk kWh	$ 0.14549	$ (0.00009)	$ 0.00392	$ 0.00704	$ 0.00004	$ 0.00236	$ 0.00056	$ 0.15932	$ 0.00205	$ -	$ 0.00205	$ 0.00191	$ 0.00396	$ 0.02416	$ 0.00250	$ 0.01859	$ 0.02109	$ 0.00050	$ 0.20903
CLC		Off Pk kWh	$ 0.01102	$ (0.00009)	$ 0.00392	$ 0.00704	$ 0.00004	$ 0.00236	$ 0.00056	$ 0.02485	$ 0.00205	$ -	$ 0.00205	$ 0.00191	$ 0.00396	$ 0.02416	$ 0.00250	$ 0.01859	$ 0.02109	$ 0.00050	$ 0.07456
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
G-1 (33)	330F	Cust	$ 5.53							$ 5.53											$ 5.53
		< 10 kW	$ -							$ -	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -
		> 10 kW	$ 4.86							$ 4.86	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ 4.86
BS		< 2300 kWh	$ 0.04071	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.05004	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ 0.02688	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.09104
BS		> 2300 kWh	$ 0.01144	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.02077	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ 0.02688	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.06177
CLC		< 2300 kWh	$ 0.04071	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.05004	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ 0.02688	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.08843
CLC		> 2300 kWh	$ 0.01144	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.02077	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ 0.02688	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.05916
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
G-1 (35)	330F	Cust	$ 5.53							$ 5.53											$ 5.53
Seasonal		< 10 kW	$ -							$ -	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ -
		> 10 kW	$ 4.31							$ 4.31	$ -	$ -	$ -		$ -	$ -	$ -		$ -	$ -	$ 4.31
BS		< 1800 kWh	$ 0.07600	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.08533	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ 0.03477	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.13422
BS		> 1800 kWh	$ 0.02415	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.03348	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ 0.03477	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.08237
CLC		< 1800 kWh	$ 0.07600	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.08533	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ 0.03477	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.13161
CLC		> 1800 kWh	$ 0.02415	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.03348	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ 0.03477	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.07976
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
G-2 (84/85/87)	331F	Cust	$ 360.13							$ 360.13											$ 360.13
		kVA	$ 1.53							$ 1.53	$ -	$ -	$ -		$ -	$ 8.02	$ -			$ -	$ 9.55
BS		Pk kWh	$ 0.01783	$ (0.00003)	$ 0.00131	$ 0.00236	$ 0.00001	$ 0.00236	$ 0.00019	$ 0.02403	$ 0.00205	$ -	$ 0.00205	$ 0.00064	$ 0.00269	$ 0.00289	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.04052
BS		Low A kWh	$ 0.01500	$ (0.00003)	$ 0.00131	$ 0.00236	$ 0.00001	$ 0.00236	$ 0.00019	$ 0.02120	$ 0.00205	$ -	$ 0.00205	$ 0.00064	$ 0.00269	$ 0.00289	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.03769
BS		Low B kWh	$ 0.00973	$ (0.00003)	$ 0.00131	$ 0.00236	$ 0.00001	$ 0.00236	$ 0.00019	$ 0.01593	$ 0.00205	$ -	$ 0.00205	$ 0.00064	$ 0.00269	$ 0.00289	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.03242
CLC		Pk kWh	$ 0.01783	$ (0.00003)	$ 0.00131	$ 0.00236	$ 0.00001	$ 0.00236	$ 0.00019	$ 0.02403	$ 0.00205	$ -	$ 0.00205	$ 0.00064	$ 0.00269	$ 0.00289	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.03791
CLC		Low A kWh	$ 0.01500	$ (0.00003)	$ 0.00131	$ 0.00236	$ 0.00001	$ 0.00236	$ 0.00019	$ 0.02120	$ 0.00205	$ -	$ 0.00205	$ 0.00064	$ 0.00269	$ 0.00289	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.03508
CLC		Low B kWh	$ 0.00973	$ (0.00003)	$ 0.00131	$ 0.00236	$ 0.00001	$ 0.00236	$ 0.00019	$ 0.01593	$ 0.00205	$ -	$ 0.00205	$ 0.00064	$ 0.00269	$ 0.00289	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.02981
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*

Rate	MDPU/MDTE No.	Blocks	Distrib.	Pension Adjust	RAAF Adjust	NMRS Adjust	AGCE Adjust	LTRCA Adjust	SCRA Adjust	Adjusted Distrib	Transition	Transition Rate Adj	Total Transition	Basic Serv Adj	Adjusted Transit	Transm.	DSM	EERF Adjust	Total Energy Efficiency	Renew.	Total Delivery
G-3 (24/25/20)	332F	Cust	$ 900.00							$ 900.00											$ 900.00
		kVA	$ 0.88							$ 0.88	$ -	$ -	$ -		$ -	$ 9.49	$ -			$ -	$ 10.37
BS		Pk kWh	$ 0.01251	$ (0.00002)	$ 0.00087	$ 0.00156	$ 0.00001	$ 0.00236	$ 0.00012	$ 0.01741	$ 0.00205	$ -	$ 0.00205	$ 0.00042	$ 0.00247	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.03079
BS		Low A kWh	$ 0.01151	$ (0.00002)	$ 0.00087	$ 0.00156	$ 0.00001	$ 0.00236	$ 0.00012	$ 0.01641	$ 0.00205	$ -	$ 0.00205	$ 0.00042	$ 0.00247	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.02979
BS		Low B kWh	$ 0.00797	$ (0.00002)	$ 0.00087	$ 0.00156	$ 0.00001	$ 0.00236	$ 0.00012	$ 0.01287	$ 0.00205	$ -	$ 0.00205	$ 0.00042	$ 0.00247	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.02625
CLC		Pk kWh	$ 0.01251	$ (0.00002)	$ 0.00087	$ 0.00156	$ 0.00001	$ 0.00236	$ 0.00012	$ 0.01741	$ 0.00205	$ -	$ 0.00205	$ 0.00042	$ 0.00247	$ -	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.02818
CLC		Low A kWh	$ 0.01151	$ (0.00002)	$ 0.00087	$ 0.00156	$ 0.00001	$ 0.00236	$ 0.00012	$ 0.01641	$ 0.00205	$ -	$ 0.00205	$ 0.00042	$ 0.00247	$ -	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.02718
CLC		Low B kWh	$ 0.00797	$ (0.00002)	$ 0.00087	$ 0.00156	$ 0.00001	$ 0.00236	$ 0.00012	$ 0.01287	$ 0.00205	$ -	$ 0.00205	$ 0.00042	$ 0.00247	$ -	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.02364
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
G-4 (41)	333F	Cust	$ 5.53							$ 5.53											$ 5.53
		kW	$ 1.75							$ 1.75	$ -	$ -	$ -		$ -	$ 2.70	$ -			$ -	$ 4.45
BS		kWh	$ 0.02003	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.02936	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ 0.00323	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.04671
CLC		kWh	$ 0.02003	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.02936	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ 0.00323	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.04410
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
G-5 (88)	334F	Cust	$ 5.40							$ 5.40											$ 5.40
BS		kWh	$ 0.03610	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.04543	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ 0.02662	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.08617
CLC		kWh	$ 0.03610	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.04543	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ 0.02662	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.08356
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
G-6 (22)	335F	Cust	$ 27.13							$ 27.13											$ 27.13
BS		kWh	$ 0.01639	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.02572	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ 0.02204	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.08188
CLC		kWh	$ 0.01639	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.02572	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ 0.02204	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.05927
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
G-7 (55/56)	336F	Cust	$ 9.13							$ 9.13											$ 9.13
		kW	$ 3.35							$ 3.35	$ -	$ -	$ -		$ -	$ 8.02	$ -			$ -	$ 11.37
BS		Pk kWh	$ 0.02301	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.03234	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.04646
BS		Low A kWh	$ 0.01612	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.02545	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.03957
CLC		Pk kWh	$ 0.02301	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.03234	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ -	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.04385
CLC		Low A kWh	$ 0.01612	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.02545	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ -	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.03698
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
G-7 (31/34)	336F	Cust	$ 9.13							$ 9.13											$ 9.13
Seasonal		kW	$ 3.39							$ 3.39	$ -	$ -	$ -		$ -	$ 3.39	$ -			$ -	$ 6.78
BS		Pk kWh	$ 0.04485	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.05418	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.06830
BS		Low A kWh	$ 0.03772	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.04705	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.06117
CLC		Pk kWh	$ 0.04485	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.05418	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ -	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.06589
CLC		Low A kWh	$ 0.03772	$ (0.00006)	$ 0.00238	$ 0.00429	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.04705	$ 0.00205	$ -	$ 0.00205	$ 0.00116	$ 0.00321	$ -	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.05856
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
SB-G3	337D	Standby Service																			
(65/67/69)		Cust	$ 900.00							$ 900.00											$ 900.00
		kVA if CD < 1000	$ 2.53							$ 2.53	$ -	$ -	$ -		$ -	$ -	$ -			$ -	$ 2.53
		kVA if CD >=1000	$ 2.87							$ 2.87	$ -	$ -	$ -		$ -	$ -	$ -			$ -	$ 2.87
		Supplemental Service																			
		Cust	No Charge							No Charge											No Charge
		kVA	$ 4.90							$ 4.90	per G-3	per G-3	per G-3	per G-3	per G-3	$ 8.17	$ -			$ -	$ 13.07
		All Use Components	$ -	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3		per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3		per G-3	
		Demand Adjustment																			
		if CD < 1000	88.4% of difference between Contract Demand and Generator Output(kW) but not more than Supplemental kVA																		
		if CD >=1000	100% of difference between Contract Demand and Generator Output(kW) but not more than Supplemental kVA																		
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
SB-G2	338D	Standby Service																			
(26/27/28)		Cust	$ 360.13							$ 360.13											$ 360.13
		kVA	$ 4.04							$ 4.04	$ -	$ -	$ -		$ -	$ -	$ -			$ -	$ 4.04
		Supplemental Service																			
		Cust	No Charge							No Charge											No Charge
		kVA	$ 6.74							$ 6.74	per G-2	per G-2	per G-2	per G-2	per G-2	$ 8.02	$ -			$ -	$ 14.76
		All Use Components	$ -	per G-2	per G-2	per G-2	per G-2	per G-2	per G-2		per G-2	per G-2	per G-2	per G-2	per G-2	per G-2	per G-2	per G-2		per G-2	
		Demand Adjustment																			
		kVA	88.4% of difference between Contract Demand and Generator Output(kW) but not more than Supplemental kVA																		
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*
S-2 (82)	341N	Fixture Charge	$ 0.75							$ 0.75											$ 0.75
BS		kWh	$ 0.03478	$ (0.00008)	$ 0.00349	$ 0.00628	$ 0.00003	$ 0.00236	$ 0.00050	$ 0.04736	$ 0.00205	$ -	$ 0.00205	$ 0.00170	$ 0.00375	$ 0.02106	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.08308
CLC		kWh	$ 0.03478	$ (0.00008)	$ 0.00349	$ 0.00628	$ 0.00003	$ 0.00236	$ 0.00050	$ 0.04736	$ 0.00205	$ -	$ 0.00205	$ 0.00170	$ 0.00375	$ 0.02106	$ 0.00250	$ 0.00530	$ 0.00780	$ 0.00050	$ 0.08047
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*1/1/18*

Rate	MDPU/MDTE No.	Blocks	Distrib.	Pension Adjust	RAAF Adjust	NMRS Adjust	AGCE Adjust	LTRCA Adjust	SCRA Adjust	Adjusted Distrib	Transition	Transition Rate Adj	Total Transition	Basic Serv Adj	Adjusted Transit	Transm.	DSM	EERF Adjust	Total Energy Efficiency	Renew.	Total Delivery
Basic Service *			01-Jan-18	01-Feb-18	01-Mar-18	01-Apr-18	01-May-18	01-Jun-18	01-Jul-18	01-Aug-18	01-Sep-18	01-Oct-18	01-Nov-18	01-Dec-18							*Last Change*
Residential	R1 - R6	Fixed	$ 0.12881	$ 0.12881	$ 0.12881	$ 0.12881	$ 0.12881	$ 0.12881													*1/1/18*
		Variable	$ 0.14875	$ 0.15305	$ 0.12558	$ 0.11683	$ 0.11165	$ 0.10663													*1/1/18*
Small C&I	G1,G4-G7	Fixed	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685													*1/1/18*
		Variable	$ 0.15031	$ 0.15418	$ 0.12408	$ 0.11230	$ 0.10764	$ 0.10579													*1/1/18*
Large C&I	G2,G3	Fixed	$ 0.11933	$ 0.11933	$ 0.11933																*1/1/18*
		Variable	$ 0.12772	$ 0.12864	$ 0.10164																*1/1/18*
St. Lighting	S1,S2	Fixed	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685													*1/1/18*
		Variable	$ 0.15031	$ 0.15418	$ 0.12408	$ 0.11230	$ 0.10764	$ 0.10579													*1/1/18*

*Includes the Basic Service Bad Debt Cost of $ 0.00123 and NSTAR Green Cost of $0.00090

Rate	MDPU/MDTE No.	Blocks	Distribution	Pension Adjust	RAAF Adjust	NMRS Adjust	AGCE Adjust	LTRCA Adjust	SCRA Adjust	Adjusted Distrib	Transition	Transition Rate Adj	Total Transition	Basic Serv Adj	Adjusted Transit.	Transmis.	DSM	EERF Adjust	Total Energy Efficiency	Renew.	Total Delivery
R-1 (A1)	120F	Cust	$ 6.43							$ 6.43											$ 6.43
		kWh	$ 0.04541	$ (0.00010)	$ 0.00224	$ 0.00716	$ 0.00004	$ 0.00236	$ 0.00057	$ 0.05768	$ (0.00138)	$ -	$ (0.00138)	$ 0.00194	$ 0.00056	$ 0.02647	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.10160
Last change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
R-2 (A2)	121G	Cust	$ 6.43							$ 6.43											$ 6.43
(Like R-1)		kWh	$ 0.04541	$ (0.00010)	$ 0.00224	$ 0.00716	$ 0.00004	$ 0.00236	$ 0.00057	$ 0.05768	$ (0.00138)	$ -	$ (0.00138)	$ 0.00194	$ 0.00056	$ 0.02646	$ 0.00250	$ 0.00083	$ 0.00333	$ 0.00050	$ 0.08853
27.0% discount on total bill																					
Last change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
R-2 (A3)	121G	Cust	$ 6.43							$ 6.43											$ 6.43
(Like R-3)		Win - kWh	$ 0.03780	$ (0.00008)	$ 0.00177	$ 0.00567	$ 0.00003	$ 0.00236	$ 0.00045	$ 0.04800	$ (0.00138)	$ -	$ (0.00138)	$ 0.00154	$ 0.00016	$ 0.02613	$ 0.00250	$ 0.00083	$ 0.00333	$ 0.00050	$ 0.07812
		Sum - kWh	$ 0.04539	$ (0.00008)	$ 0.00177	$ 0.00567	$ 0.00003	$ 0.00236	$ 0.00045	$ 0.05559	$ (0.00138)	$ -	$ (0.00138)	$ 0.00154	$ 0.00016	$ 0.02613	$ 0.00250	$ 0.00083	$ 0.00333	$ 0.00050	$ 0.08571
25.7% discount on total bill																					
Last change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
R-3 (A4)	122F	Cust	$ 6.43							$ 6.43											$ 6.43
		Win - kWh	$ 0.03780	$ (0.00008)	$ 0.00177	$ 0.00567	$ 0.00003	$ 0.00236	$ 0.00045	$ 0.04800	$ (0.00138)	$ -	$ (0.00138)	$ 0.00154	$ 0.00016	$ 0.02613	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.09118
		Sum - kWh	$ 0.04539	$ (0.00008)	$ 0.00177	$ 0.00567	$ 0.00003	$ 0.00236	$ 0.00045	$ 0.05559	$ (0.00138)	$ -	$ (0.00138)	$ 0.00154	$ 0.00016	$ 0.02613	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.09877
Last change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
R-4 (A5/A6)	123F	Cust	$ 9.99							$ 9.99											$ 9.99
		Win - Pk kWh	$ 0.05512	$ (0.00010)	$ 0.00224	$ 0.00716	$ 0.00004	$ 0.00236	$ 0.00057	$ 0.06739	$ (0.00138)	$ -	$ (0.00138)	$ 0.00194	$ 0.00056	$ 0.08263	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.16747
		- Off Pk kWh	$ 0.02173	$ (0.00010)	$ 0.00224	$ 0.00716	$ 0.00004	$ 0.00236	$ 0.00057	$ 0.03400	$ (0.00138)	$ -	$ (0.00138)	$ 0.00194	$ 0.00056	$ -	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.05145
		Sum - Pk kWh	$ 0.10909	$ (0.00010)	$ 0.00224	$ 0.00716	$ 0.00004	$ 0.00236	$ 0.00057	$ 0.12136	$ (0.00138)	$ -	$ (0.00138)	$ 0.00194	$ 0.00056	$ 0.10912	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.24793
		- Off Pk kWh	$ 0.02276	$ (0.00010)	$ 0.00224	$ 0.00716	$ 0.00004	$ 0.00236	$ 0.00057	$ 0.03503	$ (0.00138)	$ -	$ (0.00138)	$ 0.00194	$ 0.00056	$ -	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.05248
Last change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
G-1 (A9)	130F	Cust	$ 8.14							$ 8.14											$ 8.14
(w/o Dem)		Win - kWh	$ 0.04585	$ (0.00011)	$ 0.00265	$ 0.00849	$ 0.00005	$ 0.00236	$ 0.00068	$ 0.05997	$ (0.00138)	$ -	$ (0.00138)	$ 0.00230	$ 0.00092	$ 0.03411	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.10591
		Sum - kWh	$ 0.07384	$ (0.00011)	$ 0.00265	$ 0.00849	$ 0.00005	$ 0.00236	$ 0.00068	$ 0.08796	$ (0.00138)	$ -	$ (0.00138)	$ 0.00230	$ 0.00092	$ 0.03411	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.13390
Last change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
G-1 (B1)	130F	Cust	$ 12.09							$ 12.09											$ 12.09
(w/ Dem)		Win - >10 kW	$ 0.28							$ 0.28	$ -	$ -	$ -		$ -	$ 18.29					$ 18.57
		1st 2000 kWh	$ 0.04201	$ (0.00011)	$ 0.00265	$ 0.00849	$ 0.00005	$ 0.00236	$ 0.00068	$ 0.05613	$ (0.00138)	$ -	$ (0.00138)	$ 0.00230	$ 0.00092	$ 0.01904	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.08700
		Next 150 hrs*kW	$ 0.03653	$ (0.00011)	$ 0.00265	$ 0.00849	$ 0.00005	$ 0.00236	$ 0.00068	$ 0.05065	$ (0.00138)	$ -	$ (0.00138)	$ 0.00230	$ 0.00092	$ 0.01904	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.08152
		remainder kWh	$ 0.02425	$ (0.00011)	$ 0.00265	$ 0.00849	$ 0.00005	$ 0.00236	$ 0.00068	$ 0.03837	$ (0.00138)	$ -	$ (0.00138)	$ 0.00230	$ 0.00092	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.05020
		Sum - >10 kW	$ 0.86							$ 0.86		$ -	$ -		$ -	$ 56.05					$ 56.91
		1st 2000 kWh	$ 0.06752	$ (0.00011)	$ 0.00265	$ 0.00849	$ 0.00005	$ 0.00236	$ 0.00068	$ 0.08164	$ (0.00138)	$ -	$ (0.00138)	$ 0.00230	$ 0.00092	$ 0.01904	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.11251
		Next 150 hrs*kW	$ 0.04098	$ (0.00011)	$ 0.00265	$ 0.00849	$ 0.00005	$ 0.00236	$ 0.00068	$ 0.05510	$ (0.00138)	$ -	$ (0.00138)	$ 0.00230	$ 0.00092	$ 0.01904	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.08597
		remainder kWh	$ 0.02549	$ (0.00011)	$ 0.00265	$ 0.00849	$ 0.00005	$ 0.00236	$ 0.00068	$ 0.03961	$ (0.00138)	$ -	$ (0.00138)	$ 0.00230	$ 0.00092	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.05144
Last change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
G-2 (B2)	131F	Cust	$ 18.19							$ 18.19											$ 18.19
		Win - >10 kW	$ 9.43							$ 9.43	$ -	$ -	$ -		$ -	$ 8.32					$ 17.75
		1st 2000 kWh	$ 0.01784	$ (0.00007)	$ 0.00172	$ 0.00552	$ 0.00003	$ 0.00236	$ 0.00044	$ 0.02784	$ (0.00138)	$ -	$ (0.00138)	$ 0.00149	$ 0.00011	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.03886
		Next 150 hrs*kW	$ 0.01279	$ (0.00007)	$ 0.00172	$ 0.00552	$ 0.00003	$ 0.00236	$ 0.00044	$ 0.02279	$ (0.00138)	$ -	$ (0.00138)	$ 0.00149	$ 0.00011	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.03381
		remainder kWh	$ 0.01092	$ (0.00007)	$ 0.00172	$ 0.00552	$ 0.00003	$ 0.00236	$ 0.00044	$ 0.02092	$ (0.00138)	$ -	$ (0.00138)	$ 0.00149	$ 0.00011	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.03194
		Sum - >10 kW	$ 20.22							$ 20.22	$ -	$ -	$ -		$ -	$ 22.04					$ 42.26
		1st 2000 kWh	$ 0.02777	$ (0.00007)	$ 0.00172	$ 0.00552	$ 0.00003	$ 0.00236	$ 0.00044	$ 0.03777	$ (0.00138)	$ -	$ (0.00138)	$ 0.00149	$ 0.00011	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.04879
		Next 150 hrs*kW	$ 0.01452	$ (0.00007)	$ 0.00172	$ 0.00552	$ 0.00003	$ 0.00236	$ 0.00044	$ 0.02452	$ (0.00138)	$ -	$ (0.00138)	$ 0.00149	$ 0.00011	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.03554
		remainder kWh	$ 0.01141	$ (0.00007)	$ 0.00172	$ 0.00552	$ 0.00003	$ 0.00236	$ 0.00044	$ 0.02141	$ (0.00138)	$ -	$ (0.00138)	$ 0.00149	$ 0.00011	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.03243
		Transfmr Credit / kW	$ (0.12)							$ (0.12)											
Last change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
G-3	132F	Cust	$ 237.07							$ 237.07											$ 237.07
(B3/B4)		Win - kW	$ 8.59							$ 8.59	$ -	$ -	$ -		$ -	$ 11.06					$ 19.65
(G8/G7)		Peak kWh	$ -	$ (0.00004)	$ 0.00087	$ 0.00280	$ 0.00002	$ 0.00236	$ 0.00022	$ 0.00623	$ (0.00138)	$ -	$ (0.00138)	$ 0.00076	$ (0.00062)	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.01652
		Off Peak kWh	$ -	$ (0.00004)	$ 0.00087	$ 0.00280	$ 0.00002	$ 0.00236	$ 0.00022	$ 0.00623	$ (0.00138)	$ -	$ (0.00138)	$ 0.00076	$ (0.00062)	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.01652
		Sum - kW	$ 14.56							$ 14.56	$ -	$ -	$ -		$ -	$ 11.06					$ 25.62
		Peak kWh	$ -	$ (0.00004)	$ 0.00087	$ 0.00280	$ 0.00002	$ 0.00236	$ 0.00022	$ 0.00623	$ (0.00138)	$ -	$ (0.00138)	$ 0.00076	$ (0.00062)	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.01652
		Off Peak kWh	$ -	$ (0.00004)	$ 0.00087	$ 0.00280	$ 0.00002	$ 0.00236	$ 0.00022	$ 0.00623	$ (0.00138)	$ -	$ (0.00138)	$ 0.00076	$ (0.00062)	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.01652
Last change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
T-1 (B5/B6)	133F	Cust	$ 10.13							$ 10.13											$ 10.13
		Win - Peak kWh	$ 0.07364	$ (0.00011)	$ 0.00265	$ 0.00849	$ 0.00005	$ 0.00236	$ 0.00068	$ 0.08776	$ (0.00138)	$ -	$ (0.00138)	$ 0.00230	$ 0.00092	$ 0.05748	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.15707
		- Off Peak kWh	$ 0.01877	$ (0.00011)	$ 0.00265	$ 0.00849	$ 0.00005	$ 0.00236	$ 0.00068	$ 0.03289	$ (0.00138)	$ -	$ (0.00138)	$ 0.00230	$ 0.00092	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.04472
		Sum - Peak kWh	$ 0.15707	$ (0.00011)	$ 0.00265	$ 0.00849	$ 0.00005	$ 0.00236	$ 0.00068	$ 0.17119	$ (0.00138)	$ -	$ (0.00138)	$ 0.00230	$ 0.00092	$ 0.12125	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.30427
		- Off Peak kWh	$ 0.02071	$ (0.00011)	$ 0.00265	$ 0.00849	$ 0.00005	$ 0.00236	$ 0.00068	$ 0.03483	$ (0.00138)	$ -	$ (0.00138)	$ 0.00230	$ 0.00092	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.04666
Last change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*

Rate	MDPU/MDTE No.	Blocks	Distribution	Pension Adjust	RAAF Adjust	NMRS Adjust	AGCE Adjust	LTRCA Adjust	SCRA Adjust	Adjusted Distrib	Transition	Transition Rate Adj	Total Transition	Basic Serv Adj	Adjusted Transit.	Transmis.	DSM	EERF Adjust	Total Energy Efficiency	Renew.	Total Delivery
T-2	134F	Cust kW<=150	$ 27.77							$ 27.77											$ 27.77
(B7/B8)		150<kw<=300	$ 114.62							$ 114.62											$ 114.62
(G8/G9)		300<kw<=1000	$ 166.67							$ 166.67											$ 166.67
		kw>1000	$ 374.57							$ 374.57											$ 374.57
		Win - kW	$ 11.20							$ 11.20	$ -	$ -	$ -		$ -	$ 10.64					$ 21.84
		Peak kWh	$ -	$ (0.00006)	$ 0.00135	$ 0.00431	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.00832	$ (0.00138)	$ -	$ (0.00138)	$ 0.00117	$ (0.00021)	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.01902
		Off Peak kWh	$ -	$ (0.00006)	$ 0.00135	$ 0.00431	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.00832	$ (0.00138)	$ -	$ (0.00138)	$ 0.00117	$ (0.00021)	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.01902
		Sum - kW	$ 19.65							$ 19.65	$ -	$ -	$ -		$ -	$ 10.64					$ 30.29
		Peak kWh	$ -	$ (0.00006)	$ 0.00135	$ 0.00431	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.00832	$ (0.00138)	$ -	$ (0.00138)	$ 0.00117	$ (0.00021)	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.01902
		Off Peak kWh	$ -	$ (0.00006)	$ 0.00135	$ 0.00431	$ 0.00002	$ 0.00236	$ 0.00034	$ 0.00832	$ (0.00138)	$ -	$ (0.00138)	$ 0.00117	$ (0.00021)	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.01902
		Transfmr Credit / kW	$ (0.12)							$ (0.12)											
Last change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
WR (E1/E2)	135G	Cust	$ 187.00							$ 187.00											$ 187.00
		Win - First 5000 kW	$ -							$ -	$ -	$ -	$ -		$ -	$ -					$ -
		>5000 kW	$ (0.27)							$ (0.27)	$ -	$ -	$ -	$ -	$ -	$ 7.70					$ 7.43
Distribution charge per kW		- kWh	$ 0.00688	$ (0.00001)	$ 0.00022	$ 0.00070	$ -	$ 0.00236	$ 0.00006	$ 0.01021	$ (0.00138)	$ -	$ (0.00138)	$ 0.00019	$ (0.00119)	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.01993
as per D.T.E. 03-88A		Sum - First 5000 kW	$ -							$ -	$ -	$ -	$ -		$ -	$ -					$ -
The transition cost adjustment		>5000 kW	$ (0.27)							$ (0.27)	$ -	$ -	$ -	$ -	$ -	$ 7.70					$ 7.43
is pursuant to D.T.E. 01-108		- kWh	$ 0.00688	$ (0.00001)	$ 0.00022	$ 0.00070	$ -	$ 0.00236	$ 0.00006	$ 0.01021	$ (0.00138)	$ -	$ (0.00138)	$ 0.00019	$ (0.00119)	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.01993
Last change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
SB-G3	136D	Standby Service																			
(C6/C7)		Cust	$ 237.07							$ 237.07											$ 237.07
(F6/F7)		Win-kW if CD < 1000	4.46							$ 4.46	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ 4.46
		kW if CD >=1000	6.25							$ 6.25	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ 6.25
		Sum-kW if CD < 1000	7.38							$ 7.38	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ 7.38
		kW if CD >=1000	10.35							$ 10.35	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ 10.35
		Supplemental Service																			
		Cust	No Charge																		$ -
		All Use Components	per G-3	per G-3	per G-3	per G-3	per G-3	per-G-3	per-G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3
		Demand Adjustment																			
		if CD < 1000	71.3% of difference between Contract Demand and Generator Output(kW) but not more than Supplemental kW																		
		if CD >=1000	100% of difference between Contract Demand and Generator Output(kW) but not more than Supplemental kW																		
Last change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
SB-T2	138C	Standby Service																			
(C8/C9)		Cust	per T-2							per T-2											per T-2
(F8/F9)		Win-kW if CD < 1000	7.35							$ 7.35	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ 7.35
		kW if CD >=1000	8.75							$ 8.75	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ 8.75
		Sum-kW if CD < 1000	12.30							$ 12.30	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ 12.30
		kW if CD >=1000	14.67							$ 14.67	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ 14.67
		Supplemental Service																			
		Cust	No Charge																		$ -
		All Use Components	per T-2	per T-2	per T-2	per T-2	per T-2	per T-2	per T-2	per T-2	per T-2	per T-2	per T-2	per T-2	per T-2	per T-2	per T-2	per T-2	per T-2	per T-2	per T-2
		Demand Adjustment																			
		if CD < 1000	84.0% of difference between Contract Demand and Generator Output(kW) but not more than Supplemental kW																		
		if CD >=1000	100% of difference between Contract Demand and Generator Output(kW) but not more than Supplemental kW																		
Last change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
S-2 (C2/C4)	141F	Cust	$ 8.02							$ 8.02											$ 8.02
		kWh	$ 0.02727	$ (0.00006)	$ 0.00145	$ 0.00465	$ 0.00003	$ 0.00236	$ 0.00037	$ 0.03607	$ (0.00138)	$ -	$ (0.00138)	$ 0.00126	$ (0.00012)	$ 0.01757	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.06443
Last change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*

Basic Service *

			01-Jan-18	01-Feb-18	01-Mar-18	01-Apr-18	01-May-18	01-Jun-18	01-Jul-18	01-Aug-18	01-Sep-18	01-Oct-18	01-Nov-18	01-Dec-18	*Last change*
Residential	R1,R2,R3,R4	Fixed	$ 0.12881	$ 0.12881	$ 0.12881	$ 0.12881	$ 0.12881	$ 0.12881							*1/1/18*
		Variable	$ 0.14875	$ 0.15305	$ 0.12558	$ 0.11683	$ 0.11165	$ 0.10663							*1/1/18*
Small C&I	G1,G2,T1	Fixed	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685							*1/1/18*
		Variable	$ 0.15031	$ 0.15418	$ 0.12408	$ 0.11230	$ 0.10764	$ 0.10579							*1/1/18*
Large C&I	G3,T2	Fixed -NEMA	$ 0.14632	$ 0.14632	$ 0.14632										*1/1/18*
		Variable -NEMA	$ 0.15155	$ 0.15685	$ 0.13007										*1/1/18*
Large C&I	G3,T2	Fixed -SEMA	$ 0.11933	$ 0.11933	$ 0.11933										*1/1/18*
		Variable -SEMA	$ 0.12772	$ 0.12884	$ 0.10164										*1/1/18*
St. Lighting	S1,S2,S3	Fixed	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685							*1/1/18*
		Variable	$ 0.15031	$ 0.15418	$ 0.12408	$ 0.11230	$ 0.10764	$ 0.10579							*1/1/18*

*Includes the Basic Service Bad Debt Cost of $ 0.00123 and NSTAR Green Cost of $0.00090

NOTE: Summer Months - June thru September
Winter Months - October thru May

Rate	MDPU/MDTE No.	Blocks	Distribution	Pension Adjust	RAAF Adjust	NMRS Adjust	AGCE Adjust	LTRCA Adjust	SCRA Adjust	Adjusted Distrib	Transition	Transition Rate Adj	Total Transition	Basic Serv Adj	Adjusted Transit	Transmis.	DSM	EERF Adjust	Total Energy Efficiency	Renew.	Total Delivery
R-1 (01)	220G	Cust	$ 6.87							$ 6.87											$ 6.87
		kWh	$ 0.03778	$ (0.00017)	$ 0.00132	$ 0.01272	$ 0.00007	$ 0.00236	$ 0.00102	$ 0.05510	$ (0.00020)	$ -	$ (0.00020)	$ 0.00345	$ 0.00325	$ 0.03551	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.11075
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
R-2 (05)	221H	Cust	$ 6.87							$ 6.87											$ 6.87
		kWh	$ 0.03778	$ (0.00017)	$ 0.00132	$ 0.01272	$ 0.00007	$ 0.00236	$ 0.00102	$ 0.05510	$ (0.00020)	$ -	$ (0.00020)	$ 0.00345	$ 0.00325	$ 0.03551	$ 0.00250	$ 0.00083	$ 0.00333	$ 0.00050	$ 0.09769
24.9% discount on total bill																					
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
R-3 (04)	222G	Cust	$ 7.77							$ 7.77											$ 7.77
		kWh	$ 0.04426	$ (0.00016)	$ 0.00123	$ 0.01189	$ 0.00006	$ 0.00236	$ 0.00095	$ 0.06059	$ (0.00020)	$ -	$ (0.00020)	$ 0.00322	$ 0.00302	$ 0.04177	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.12227
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
R-4 (07)	223H	Cust	$ 7.77							$ 7.77											$ 7.77
		kWh	$ 0.04426	$ (0.00016)	$ 0.00123	$ 0.01189	$ 0.00006	$ 0.00236	$ 0.00095	$ 0.06059	$ (0.00020)	$ -	$ (0.00020)	$ 0.00322	$ 0.00302	$ 0.04177	$ 0.00250	$ 0.00083	$ 0.00333	$ 0.00050	$ 0.10921
24.8% discount on total bill																					
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
R-5 (TOU)	224G	Cust	$ 10.47							$ 10.47											$ 10.47
Non-Htg		Pk kWh	$ 0.10152	$ (0.00017)	$ 0.00132	$ 0.01272	$ 0.00007	$ 0.00236	$ 0.00102	$ 0.11884	$ (0.00020)	$ -	$ (0.00020)	$ 0.00345	$ 0.00325	$ 0.07978	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.21876
(48/49)		Off Pk kWh	$ 0.01969	$ (0.00017)	$ 0.00132	$ 0.01272	$ 0.00007	$ 0.00236	$ 0.00102	$ 0.03701	$ (0.00020)	$ -	$ (0.00020)	$ 0.00345	$ 0.00325	$ -	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.05715
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
R-6 (TOU)	225G	Cust	$ 11.37							$ 11.37											$ 11.37
Htg		Pk kWh	$ 0.13212	$ (0.00016)	$ 0.00123	$ 0.01189	$ 0.00006	$ 0.00236	$ 0.00095	$ 0.14845	$ (0.00020)	$ -	$ (0.00020)	$ 0.00322	$ 0.00302	$ 0.15777	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.32613
(10/16)		Off Pk kWh	$ 0.02534	$ (0.00016)	$ 0.00123	$ 0.01189	$ 0.00006	$ 0.00236	$ 0.00095	$ 0.04167	$ (0.00020)	$ -	$ (0.00020)	$ 0.00322	$ 0.00302	$ -	$ 0.00250	$ 0.01389	$ 0.01639	$ 0.00050	$ 0.06158
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
G-0 (06)	230G	Cust	$ 4.62							$ 4.62											$ 4.62
(w/o Dem)		kWh	$ 0.03363	$ (0.00012)	$ 0.00095	$ 0.00921	$ 0.00005	$ 0.00236	$ 0.00074	$ 0.04682	$ (0.00020)	$ -	$ (0.00020)	$ 0.00249	$ 0.00229	$ 0.03329	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.09331
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
G-1	231G	Cust	$ 7.32							$ 7.32											$ 7.32
(w/ Dem)		< 10 kW	$ 3.76							$ 3.76	$ -	$ -	$ -	$ -	$ -	$ 9.93	$ -			$ -	$ 13.69
(02)		> 10 kW	$ 7.01							$ 7.01	$ -	$ -	$ -	$ -	$ -	$ 9.93	$ -			$ -	$ 16.94
		kWh	$ 0.01131	$ (0.00009)	$ 0.00070	$ 0.00679	$ 0.00004	$ 0.00236	$ 0.00054	$ 0.02165	$ (0.00020)	$ -	$ (0.00020)	$ 0.00184	$ 0.00164	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.03420
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
G-2	232G	Cust	$ 90.00							$ 90.00											$ 90.00
(62/63/64)		< 100 kVA	$ 4.06							$ 4.06	$ -	$ -	$ -	$ -	$ -	$ 6.83	$ -			$ -	$ 10.89
		> 100 kVA	$ 5.03							$ 5.03	$ -	$ -	$ -	$ -	$ -	$ 14.04	$ -			$ -	$ 19.07
		Pk kWh	$ 0.00952	$ (0.00006)	$ 0.00049	$ 0.00474	$ 0.00003	$ 0.00236	$ 0.00038	$ 0.01746	$ (0.00020)	$ -	$ (0.00020)	$ 0.00128	$ 0.00108	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.02945
		Low A kWh	$ 0.00952	$ (0.00006)	$ 0.00049	$ 0.00474	$ 0.00003	$ 0.00236	$ 0.00038	$ 0.01746	$ (0.00020)	$ -	$ (0.00020)	$ 0.00128	$ 0.00108	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.02945
		Low B kWh	$ 0.00952	$ (0.00006)	$ 0.00049	$ 0.00474	$ 0.00003	$ 0.00236	$ 0.00038	$ 0.01746	$ (0.00020)	$ -	$ (0.00020)	$ 0.00128	$ 0.00108	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.02945
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
G-3	233G	Cust	$ 90.00							$ 90.00											$ 90.00
(70/71/72)		First 100 kVA	$ -							$ -	$ -	$ -	$ -	$ -	$ -	$ 448.60	$ -			$ -	$ 448.60
		> 100 kVA	$ 4.32							$ 4.32	$ -	$ -	$ -	$ -	$ -	$ 8.60	$ -			$ -	$ 12.92
		Pk kWh	$ 0.00330	$ (0.00003)	$ 0.00023	$ 0.00226	$ 0.00001	$ 0.00236	$ 0.00018	$ 0.00831	$ (0.00020)	$ -	$ (0.00020)	$ 0.00061	$ 0.00041	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.01963
		Low A kWh	$ 0.00330	$ (0.00003)	$ 0.00023	$ 0.00226	$ 0.00001	$ 0.00236	$ 0.00018	$ 0.00831	$ (0.00020)	$ -	$ (0.00020)	$ 0.00061	$ 0.00041	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.01963
		Low B kWh	$ 0.00330	$ (0.00003)	$ 0.00023	$ 0.00226	$ 0.00001	$ 0.00236	$ 0.00018	$ 0.00831	$ (0.00020)	$ -	$ (0.00020)	$ 0.00061	$ 0.00041	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.01963
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
G-4	234G	Cust	$ 10.92							$ 10.92											$ 10.92
(52/53)		kW	$ 4.16							$ 4.16	$ -	$ -	$ -	$ -	$ -	$ 9.68	$ -			$ -	$ 13.84
		Pk kWh	$ 0.01043	$ (0.00009)	$ 0.00070	$ 0.00679	$ 0.00004	$ 0.00236	$ 0.00054	$ 0.02077	$ (0.00020)	$ -	$ (0.00020)	$ 0.00184	$ 0.00164	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.03332
		Low A kWh	$ 0.01043	$ (0.00009)	$ 0.00070	$ 0.00679	$ 0.00004	$ 0.00236	$ 0.00054	$ 0.02077	$ (0.00020)	$ -	$ (0.00020)	$ 0.00184	$ 0.00164	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.03332
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
G-5	235G	Cust	$ 7.20							$ 7.20											$ 7.20
(36)		< 5000 kWh	$ 0.01777	$ (0.00009)	$ 0.00070	$ 0.00679	$ 0.00004	$ 0.00236	$ 0.00054	$ 0.02811	$ (0.00020)	$ -	$ (0.00020)	$ 0.00164	$ 0.00164	$ 0.03045	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.07111
		> 5000 kWh	$ 0.02335	$ (0.00009)	$ 0.00070	$ 0.00679	$ 0.00004	$ 0.00236	$ 0.00054	$ 0.03369	$ (0.00020)	$ -	$ (0.00020)	$ 0.00184	$ 0.00164	$ 0.03899	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.08523
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
G-6	236G	Cust	$ 8.22							$ 8.22											$ 8.22
(51/54)		Pk kWh	$ 0.06346	$ (0.00012)	$ 0.00095	$ 0.00921	$ 0.00005	$ 0.00236	$ 0.00074	$ 0.07665	$ (0.00020)	$ -	$ (0.00020)	$ 0.00249	$ 0.00229	$ 0.11293	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.20278
		Low A kWh	$ 0.02338	$ (0.00012)	$ 0.00095	$ 0.00921	$ 0.00005	$ 0.00236	$ 0.00074	$ 0.03657	$ (0.00020)	$ -	$ (0.00020)	$ 0.00249	$ 0.00229	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.04977
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*

Rate	MDPU/MDTE No.	Blocks	Distribution	Pension Adjust	RAAF Adjust	NMRS Adjust	AGCE Adjust	LTRCA Adjust	SCRA Adjust	Adjusted Distrib	Transition	Transition Rate Adj	Total Transition	Basic Serv Adj	Adjusted Transit	Transmis.	DSM	EERF Adjust	Total Energy Efficiency	Renew.	Total Delivery
SB-1	237H	Standby Service																			
(D1/D2/D3)		Cust	$ 781.00							$ 781.00											$ 781.00
		Standby Capacity (Peak kVA)								$ -	$ -	$ -	$ -	$ -	$ -	$ 11.88					$ 11.88
		kVA (Max replacement)	$ 4.37							$ 4.37											$ 4.37
		Minimum Reservation	$ -							$ -	$ -	$ -	$ -	$ -	$ -	$ 0.36					$ 0.36
		kWh (replacement)	$ -	$ (0.00003)	$ 0.00023	$ 0.00226	$ 0.00001	$ 0.00236	$ 0.00018	$ 0.00501	$ (0.00020)	$ -	$ (0.00020)	$ 0.00061	$ 0.00041	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.01633
MS-1	238H	Maintenance Service																			
(D4/D5/D6)		Cust	$ 781.00	No charge if billed under SB-1						$ 781.00											$ 781.00
		kVA (Max replacement)	$ 4.37	No charge if billed under SB-1						$ 4.37	$ -	$ -	$ -	$ -	$ -						$ 4.37
		kWh (replacement)	$ -	$ (0.00003)	$ 0.00023	$ 0.00226	$ 0.00001	$ 0.00236	$ 0.00018	$ 0.00501	$ (0.00020)	$ -	$ (0.00020)	$ 0.00061	$ 0.00041	$ -	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.01633
SS-1	239F	Supplemntal Service																			
(D7/D8/D9)		Cust	No Charge																		
		All rate components	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
SB-G2	254E	Standby Service																			
(43/44/45)		Cust	$ 90.00							$ 90.00											$ 90.00
		kVA if CD < 1000																			
		< 100 kVA	$ 1.81							$ 1.81	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ 1.81
		> 100 kVA	$ 2.41							$ 2.41	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ 2.41
		kVA if CD >=1000																			
		< 100 kVA	$ 2.84							$ 2.84	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ 2.84
		> 100 kVA	$ 3.79							$ 3.79	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ 3.79
		Supplemental Service																			
		Cust	No Charge																		No Charge
		all kVA	$ 8.95							$ 8.95	per G-2	per G-2	per G-2	per G-2	per G-2	per G-2	$ -			$ -	
		All Use Components	$ -	per G-2	per G-2	per G-2	per G-2	per G-2	per G-2		per G-2	per G-2	per G-2	per G-2	per G-2	per G-2	per G-2	per G-2	per G-2	per G-2	
		Demand Adjustment																			
		if CD < 1000	Per tariff																		
		if CD >=1000	Per tariff																		
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
SB-G3	255E	Standby Service																			
(46/47/50)		Cust	$ 90.00							$ 90.00											$ 90.00
		kVA if CD < 1000																			
		< 100 kVA	$ -							$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ -
		> 100 kVA	$ 0.79							$ 0.79	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ 0.79
		kVA if CD >=1000																			
		< 100 kVA	$ -							$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ -
		> 100 kVA	$ 1.79							$ 1.79	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -	$ 1.79
		Supplemental Service																			
		Cust	No Charge																		No Charge
		< 100 kVA	$ -							$ -	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	$ -			$ -	
		> 100 kVA	$ 6.37							$ 6.37	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	$ -			$ -	
		All Use Components	$ -	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3		per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	
		Demand Adjustment																			
		if CD < 1000	Per tariff																		
		if CD >=1000	Per tariff																		
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*
S-2 (83)	241L	Cust	$ -							$ -											$ -
		kWh	$ 0.04258	$ (0.00022)	$ 0.00169	$ 0.01632	$ 0.00009	$ 0.00236	$ 0.00131	$ 0.06413	$ (0.00020)	$ -	$ (0.00020)	$ 0.00442	$ 0.00422	$ 0.02778	$ 0.00250	$ 0.00791	$ 0.01041	$ 0.00050	$ 0.10704
Last Change			*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*1/1/18*

Basic Service *			01-Jan-18	01-Feb-18	01-Mar-18	01-Apr-18	01-May-18	01-Jun-18	01-Jul-18	01-Aug-18	01-Sep-18	01-Oct-18	01-Nov-18	01-Dec-18	Last Change
Residential	R1 - R6	Fixed	$ 0.12881	$ 0.12881	$ 0.12881	$ 0.12881	$ 0.12881	$ 0.12881							1/1/18
		Variable	$ 0.14875	$ 0.15305	$ 0.12558	$ 0.11683	$ 0.11165	$ 0.10663							1/1/18
Small C&I	G0,G1,G4-G6	Fixed	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685							1/1/18
		Variable	$ 0.15031	$ 0.15418	$ 0.12408	$ 0.11230	$ 0.10764	$ 0.10579							1/1/18
Large C&I	G2,G3	Fixed	$ 0.14632	$ 0.14632	$ 0.14632										1/1/18
		Variable	$ 0.15155	$ 0.15685	$ 0.13007										1/1/18
St. Lighting	S1,S2	Fixed	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685	$ 0.12685							1/1/18
		Variable	$ 0.15031	$ 0.15418	$ 0.12408	$ 0.11230	$ 0.10764	$ 0.10579							1/1/18

*Includes the Basic Service Bad Debt Cost of $ 0.00123 and NSTAR Green Cost of $0.00090

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS

Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	Energy Efficiency Charge (EEC) System Benefits	EEC Recon. Factor	EEC Total EEC	Renewable Energy	Total Delivery
R-1	7	A1/A5	ALL	Customer	$7.00		$7.00								$7.00
Residential		01/48		Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.01389	$0.01639	$0.00050	$0.10831
		32/66/68	CAPE	Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.01859	$0.02109	$0.00050	$0.11301
Last change		57/58/39			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
R-2	8	A2	ALL	Customer	$7.00		$7.00								$7.00
Residential		05		Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.00083	$0.00333	$0.00050	$0.09525
Assistance		30/37/38	CAPE	Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.00148	$0.00398	$0.00050	$0.09590
				Discount	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
R-3	9	A4/A8	ALL	Customer	$7.00		$7.00								$7.00
Residential		04/10		Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.01389	$0.01639	$0.00050	$0.09802
Space Heating		86		Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.01859	$0.02109	$0.00050	$0.10272
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
R-4	10	A3	ALL	Customer	$7.00		$7.00								$7.00
Residential Space		07		Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.00083	$0.00333	$0.00050	$0.08496
Heating Assistance		42		Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.00148	$0.00398	$0.00050	$0.08561
				Discount	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
				Non-Demand											
G-1	11	A9	BOST	Customer	$8.00		$8.00								$8.00
General Service				Energy (kWh) - Winter	$0.04107	$0.01907	$0.06014	$0.00000	($0.00061)	$0.02586	$0.00250	$0.00791	$0.01041	$0.00050	$0.09630
				Energy (kWh) - Summer	$0.06614	$0.01907	$0.08521	$0.00000	($0.00061)	$0.02586	$0.00250	$0.00791	$0.01041	$0.00050	$0.12137
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
				Demand											
		B1	BOST	Customer	$11.00		$11.00								$11.00
				Demand (>10 kW) - Winter	$0.25		$0.25			$18.19					$18.44
				1st 2000 kWh	$0.03857	$0.01907	$0.05764	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00791	$0.01041	$0.00050	$0.08725
				Next 150 hrs*kW	$0.03354	$0.01907	$0.05261	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00791	$0.01041	$0.00050	$0.08222
				remainder kWh	$0.02226	$0.01907	$0.04133	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.05163
				Demand (>10 kW) - Summer	$0.78		$0.78			$56.49					$57.27
				1st 2000 kWh	$0.06199	$0.01907	$0.08106	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00791	$0.01041	$0.00050	$0.11067
				Next 150 hrs*kW	$0.03762	$0.01907	$0.05669	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00791	$0.01041	$0.00050	$0.08630
				remainder kWh	$0.02340	$0.01907	$0.04247	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.05277
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS

Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	Energy Efficiency Charge (EEC) System Benefits	EEC Recon. Factor	EEC Total EEC	Renewable Energy	Total Delivery
G-2	12	B2	BOST	Customer	$18.00		$18.00								$18.00
General Service				Demand (>10 kW) - Winter	$8.89		$8.89			$8.73					$17.62
				1st 2000 kWh	$0.01682	$0.01265	$0.02947	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03977
				Next 150 hrs*kW	$0.01206	$0.01265	$0.02471	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03501
				remainder kWh	$0.01029	$0.01265	$0.02294	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03324
				Demand (>10 kW) - Summer	$19.06		$19.06			$23.43					$42.49
				1st 2000 kWh	$0.02618	$0.01265	$0.03883	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.04913
				Next 150 hrs*kW	$0.01369	$0.01265	$0.02634	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03664
				remainder kWh	$0.01076	$0.01265	$0.02341	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03371
				Transformer Credit / kW	($0.12)		($0.12)								($0.12)
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
G-3	13	B3 (NEMA)	BOST	Customer	$250.00		$250.00								$250.00
General Service		G6 (SEMA)		Demand (kW) - Winter	$8.58		$8.58			$10.28					$18.86
				Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01871
				Off Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01871
				Demand (kW) - Summer	$14.54		$14.54			$10.28					$24.82
				Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01871
				Off Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01871
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
T-1	14	B5	BOST	Customer	$10.00		$10.00								$10.00
Optional				Peak kWh - Winter	$0.06494	$0.01907	$0.08401	$0.00000	($0.00061)	$0.07833	$0.00250	$0.00791	$0.01041	$0.00050	$0.17264
General Service				Off Peak kWh - Winter	$0.01655	$0.01907	$0.03562	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.04592
TOU				Peak kWh - Summer	$0.13852	$0.01907	$0.15759	$0.00000	($0.00061)	$0.17133	$0.00250	$0.00791	$0.01041	$0.00050	$0.33922
(closed)				Off Peak kWh - Summer	$0.01826	$0.01907	$0.03733	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.04763
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
T-2	15	B7 (NEMA)	BOST	Customer (kW<=150)	$27.00		$27.00								$27.00
General Service		G8 (SEMA)		Customer (150<kW<=300)	$110.00		$110.00								$110.00
TOU				Customer (300<kW<=1000)	$160.00		$160.00								$160.00
				Customer (kW>1000)	$360.00		$360.00								$360.00
				Demand (kW) - Winter	$10.58		$10.58			$9.00					$19.58
				Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02295
				Off Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02295
				Demand (kW) - Summer	$18.57		$18.57			$9.00					$27.57
				Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02295
				Off Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02295
				Transformer Credit / kW	($0.12)		($0.12)								
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
WR	16	E1	BOST	Customer	$150.48		$150.48								$150.48
MWRA				Demand (kW)	$0.00		$0.00			$6.93					$6.93
				Energy (kWh)	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01871
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS

Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	Energy Efficiency Charge (EEC)			Renewable Energy	Total Delivery
											System Benefits	Recon. Factor	Total EEC		
SB-G3	17	C6 (NEMA)	BOST	Customer	$250.00		$250.00								$250.00
General Service		F6 (SEMA)		Standby Demand<1MW (Winter)	$4.45		$4.45								$4.45
Standby				Standby Demand=>1 MW (Winter)	$6.24		$6.24								$6.24
				Standby Demand<1MW (Summer)	$7.37		$7.37								$7.37
				Standby Demand=>1MW (Summer)	$10.34		$10.34								$10.34
				Supplemental Service	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
G-0 General	18	06	CAMB	Customer	$5.00		$5.00								$5.00
(Non-Demand)				Energy (kWh)	$0.03300	$0.01092	$0.04392	$0.00000	($0.00061)	$0.02711	$0.00250	$0.00791	$0.01041	$0.00050	$0.08133
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
G-1 General	19	02	CAMB	Customer	$8.00		$8.00								$8.00
				Demand (<=10 kW)	$3.74		$3.74			$8.67					$12.41
				Demand (> 10 kW)	$6.99		$6.99			$8.67					$15.66
				Energy (kWh)	$0.01127	$0.01092	$0.02219	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03249
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
G-2	20	62	CAMB	Customer	$97.00		$97.00								$97.00
Large General				Demand (<=100 kVA)	$4.04		$4.04			$5.46					$9.50
Secondary				Demand (> 100 kVA)	$5.01		$5.01			$11.16					$16.17
Service				Peak kWh	$0.00949	$0.00840	$0.01789	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02819
				Low A kWh	$0.00949	$0.00840	$0.01789	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02819
				Low B kWh	$0.00949	$0.00840	$0.01789	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02819
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
G-3	21	70	CAMB	Customer	$97.00		$97.00								$97.00
Large General				Demand (<=100 kVA)	$0.00		$0.00			$477.65					$477.65
TOU				Demand (> 100 kVA)	$4.31		$4.31			$8.48					$12.79
13.8 kV Service				Peak kWh	$0.00329	$0.00560	$0.00889	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01919
				Low A kWh	$0.00329	$0.00560	$0.00889	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01919
				Low B kWh	$0.00329	$0.00560	$0.00889	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01919
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
G-4	22	52	CAMB	Customer	$12.00		$12.00								$12.00
Optional General				Demand (kW)	$4.14		$4.14			$9.98					$14.12
TOU				Peak kWh	$0.01038	$0.00785	$0.01823	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02853
				Low A kWh	$0.01038	$0.00785	$0.01823	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02853
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
G-5	23	36	CAMB	Customer	$8.00		$8.00								$8.00
Commercial				Energy (<=5000 kWh)	$0.01770	$0.00811	$0.02581	$0.00000	($0.00061)	$0.02390	$0.00250	$0.00791	$0.01041	$0.00050	$0.06001
Space Heating				Energy (>5000 kWh)	$0.02326	$0.00811	$0.03137	$0.00000	($0.00061)	$0.03408	$0.00250	$0.00791	$0.01041	$0.00050	$0.07575
(closed)															
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS

Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	Energy Efficiency Charge (EEC) System Benefits	EEC Recon. Factor	EEC Total EEC	Renewable Energy	Total Delivery
G-6	24	51	CAMB	Customer	$8.22		$8.22								$8.22
Optional General				Peak kWh	$0.06346	$0.01092	$0.07438	$0.00000	($0.00061)	$0.02711	$0.00250	$0.00791	$0.01041	$0.00050	$0.11179
TOU				Low A kWh	$0.02338	$0.01092	$0.03430	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.04460
(Non-Demand)															
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
SB-1	25	D1	CAMB	Customer	$781.00		$781.00								$781.00
Standby				Standby Demand/Replacement	$4.37		$4.37			$7.99					$12.36
				Minimum Reservation	$0.00		$0.00			$0.61					$0.61
				Replacement Energy	$0.00000	$0.00560	$0.00560	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01590
MS-1	26	D4	CAMB	Customer	$781.00		$781.00								$781.00
Maintenance				Standby Demand/Replacement	$4.37		$4.37								$4.37
				Replacement Energy	$0.00000	$0.00560	$0.00560	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01590
SS-1				Customer	$0.00										
Supplemental	27	D7		All Rate Components	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
SB-G3	28	46	CAMB	Customer	$97.00		$97.00								$97.00
General Service				Standby Demand<=1MW											
Standby				<=100 kVA	$0.00		$0.00								$0.00
				>100 kVA	$0.78		$0.78								$0.78
				Standby Demand=>1 MW											
				<=100 kVA	$0.00		$0.00								$0.00
				>100 kVA	$1.78		$1.78								$1.78
				Supplemental Demand											
				<=100 kVA	$0.00		$0.00			$477.65					$477.65
				>100 kVA	$6.36		$6.36			$8.48					$14.84
				Supplemental Energy	$0.00000	$0.00560	$0.00560	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01590
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
				Annual/Seasonal Optional											
G-1 General	29	33/23	SOUTH	Customer	$6.00		$6.00								$6.00
				Demand (<=10 kW)	$0.00		$0.00								$0.00
				Demand (>10 kW)	$4.85		$4.85								$4.85
				Energy (< =2300 kWh)	$0.04067	$0.01178	$0.05245	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00791	$0.01041	$0.00050	$0.08911
				Energy (>2300 kWh)	$0.01102	$0.01178	$0.02280	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00791	$0.01041	$0.00050	$0.05946
			CAPE	Energy (< =2300 kWh)	$0.04067	$0.01178	$0.05245	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.08650
			CAPE	Energy (>2300 kWh)	$0.01102	$0.01178	$0.02280	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.05685
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
				Seasonal											
		35	SOUTH	Cust	$6.00		$6.00								$6.00
				Demand (<=10 kW)	$0.00		$0.00								$0.00
				Demand (>10 kW)	$4.25		$4.25								$4.25
				Energy (< =1800 kWh)	$0.07506	$0.01178	$0.08684	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00791	$0.01041	$0.00050	$0.12350
				Energy (>1800 kWh)	$0.02385	$0.01178	$0.03563	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00791	$0.01041	$0.00050	$0.07229
			CAPE	Energy (< =1800 kWh)	$0.07506	$0.01178	$0.08684	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.12089
			CAPE	Energy (>1800 kWh)	$0.02385	$0.01178	$0.03563	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.06968
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	1/1/02	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS														
										Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
G-2	30	84	SOUTH	Cust	$370.00		$370.00								$370.00
Medium General				Demand (kVA)	$1.51		$1.51			$8.16					$9.67
TOU				Peak kWh	$0.01769	$0.00802	$0.02571	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00791	$0.01041	$0.00050	$0.03878
				Low A kWh	$0.01488	$0.00802	$0.02290	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00791	$0.01041	$0.00050	$0.03597
				Low B kWh	$0.00965	$0.00802	$0.01767	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00791	$0.01041	$0.00050	$0.03074
			CAPE	Peak kWh	$0.01769	$0.00802	$0.02571	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00530	$0.00780	$0.00050	$0.03617
			CAPE	Low A kWh	$0.01488	$0.00802	$0.02290	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00530	$0.00780	$0.00050	$0.03336
			CAPE	Low B kWh	$0.00965	$0.00802	$0.01767	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00530	$0.00780	$0.00050	$0.02813
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
G-3	31	24	SOUTH	Customer	$930.00		$930.00								$930.00
Large General				Demand (kVA)	$0.87		$0.87			$8.22					$9.09
TOU				Energy (kWh) - Peak	$0.01242	$0.00609	$0.01851	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02881
				Energy (kWh) - Low A	$0.01142	$0.00609	$0.01751	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02781
				Energy (kWh) - Low B	$0.00791	$0.00609	$0.01400	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02430
			CAPE	Energy (kWh) - Peak	$0.01242	$0.00609	$0.01851	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.02620
			CAPE	Energy (kWh) - Low A	$0.01142	$0.00609	$0.01751	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.02520
			CAPE	Energy (kWh) - Low B	$0.00791	$0.00609	$0.01400	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.02169
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	1/1/02	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
G-4	32	41	SOUTH	Customer	$6.00		$6.00								$6.00
General Power				Demand (kW)	$1.74		$1.74			$2.69					$4.43
				Energy (kWh)	$0.01998	$0.01064	$0.03062	$0.00000	($0.00061)	$0.00326	$0.00250	$0.00791	$0.01041	$0.00050	$0.04418
			CAPE	Energy (kWh)	$0.01998	$0.01064	$0.03062	$0.00000	($0.00061)	$0.00326	$0.00250	$0.00530	$0.00780	$0.00050	$0.04157
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
G-5	33	88	SOUTH	Customer	$6.00		$6.00								$6.00
Commercial				Energy (kWh)	$0.03563	$0.01235	$0.04798	$0.00000	($0.00061)	$0.03267	$0.00250	$0.00791	$0.01041	$0.00050	$0.09095
Space Heating			CAPE	Energy (kWh)	$0.03563	$0.01235	$0.04798	$0.00000	($0.00061)	$0.03267	$0.00250	$0.00530	$0.00780	$0.00050	$0.08834
(Closed)															
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
G-6	34	22	SOUTH	Customer	$30.00		$30.00								$30.00
All Electric School				Energy (kWh)	$0.01633	$0.00700	$0.02333	$0.00000	($0.00061)	$0.02666	$0.00250	$0.00791	$0.01041	$0.00050	$0.06029
(Closed)			CAPE	Energy (kWh)	$0.01633	$0.00700	$0.02333	$0.00000	($0.00061)	$0.02666	$0.00250	$0.00530	$0.00780	$0.00050	$0.05768
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
				Annual											
G-7	35	55	SOUTH	Customer	$10.00		$10.00								$10.00
Optional General				Demand (kW)	$3.33		$3.33			$10.63					$13.96
TOU				Peak kWh	$0.02290	$0.01178	$0.03468	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.04498
				Low A kWh	$0.01604	$0.01178	$0.02782	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03812
			CAPE	Peak kWh	$0.02290	$0.01178	$0.03468	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.04237
			CAPE	Low A kWh	$0.01604	$0.01178	$0.02782	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.03551
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
				Seasonal											
		31	SOUTH	Customer	$10.00		$10.00								$10.00
				Demand (kW)	$3.36		$3.36			$4.96					$8.32
				Peak kWh	$0.04453	$0.01178	$0.05631	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.06661
				Low A kWh	$0.03745	$0.01178	$0.04923	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.05953
			CAPE	Peak kWh	$0.04453	$0.01178	$0.05631	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.06400
			CAPE	Low A kWh	$0.03745	$0.01178	$0.04923	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.05692
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS																
												Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
S-1	44	C1/C3	ALL	Fixture Charge	Per Rate Schedule		Per Rate Schedule								Per Rate Schedule
Street and		19/80		Energy (kWh)		$0.01055		$0.00000	($0.00061)	$0.01258	$0.00250	$0.00791	$0.01041	$0.00050	
Security Lighting		79/81	CAPE	Energy (kWh)		$0.01055		$0.00000	($0.00061)	$0.01258	$0.00250	$0.00530	$0.00780	$0.00050	
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
S-2	45	C2/C4	ALL	Customer	$6.49		$6.49								$6.49
Street and Security -		81		Energy (kWh)	$0.02462	$0.01055	$0.03517	$0.00000	($0.00061)	$0.01258	$0.00250	$0.00791	$0.01041	$0.00050	$0.05805
Customer Owned		82	CAPE	Energy (kWh)	$0.02462	$0.01055	$0.03517	$0.00000	($0.00061)	$0.01258	$0.00250	$0.00530	$0.00780	$0.00050	$0.05544
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*

(2) Transmission Charge for Rate R-2 customers in the Boston service area is $0.03057 from February 1, 2018 through December 31, 2018

Summer Months - June thru September
Winter Months - October thru May

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

EASTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
R-1 Residential *Last change*	7	ALL	($0.00011) *2/1/18*	$0.00375 *2/1/18*	$0.00738 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00231 *2/1/18*	$0.00000 *2/1/18*	$0.00200 *2/1/18*	$0.01773 *2/1/18*
R-2 Residential Assistance *Last change*	8	ALL	($0.00011) *2/1/18*	$0.00375 *2/1/18*	$0.00738 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00231 *2/1/18*	$0.00000 *2/1/18*	$0.00200 *2/1/18*	$0.01773 *2/1/18*
R-3 Residential Space Heating *Last change*	9	ALL	($0.00010) *2/1/18*	$0.00295 *2/1/18*	$0.00580 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00182 *2/1/18*	$0.00000 *2/1/18*	$0.00157 *2/1/18*	$0.01443 *2/1/18*
R-4 Residential Space Heating Assistance *Last change*	10	ALL	($0.00010) *2/1/18*	$0.00295 *2/1/18*	$0.00580 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00182 *2/1/18*	$0.00000 *2/1/18*	$0.00157 *2/1/18*	$0.01443 *2/1/18*
G-1 General Service *Last change*	11	BOST	($0.00011) *2/1/18*	$0.00407 *2/1/18*	$0.00803 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00251 *2/1/18*	$0.00000 *2/1/18*	$0.00217 *2/1/18*	$0.01907 *2/1/18*
G-2 General Service *Last change*	12	BOST	($0.00005) *2/1/18*	$0.00250 *2/1/18*	$0.00493 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00154 *2/1/18*	$0.00000 *2/1/18*	$0.00134 *2/1/18*	$0.01265 *2/1/18*
G-3 General Service *Last change*	13	BOST	($0.00003) *2/1/18*	$0.00147 *2/1/18*	$0.00290 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00091 *2/1/18*	$0.00000 *2/1/18*	$0.00078 *2/1/18*	$0.00841 *2/1/18*
T-1 General Service Optional Time-of-Use *Last change*	14	BOST	($0.00011) *2/1/18*	$0.00407 *2/1/18*	$0.00803 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00251 *2/1/18*	$0.00000 *2/1/18*	$0.00217 *2/1/18*	$0.01907 *2/1/18*
T-2 General Service Time-of-Use *Last change*	15	BOST	($0.00005) *2/1/18*	$0.00250 *2/1/18*	$0.00493 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00154 *2/1/18*	$0.00000 *2/1/18*	$0.00134 *2/1/18*	$0.01265 *2/1/18*
WR MWRA *Last Change*	16	BOST	($0.00003) *2/1/18*	$0.00147 *2/1/18*	$0.00290 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00091 *2/1/18*	$0.00000 *2/1/18*	$0.00078 *2/1/18*	$0.00841 *2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

EASTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
G-0 General (Non-Demand)	18	CAMB	($0.00006)	$0.00209	$0.00411	$0.00002	$0.00236	$0.00129	$0.00000	$0.00111	$0.01092
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-1 General	19	CAMB	($0.00006)	$0.00209	$0.00411	$0.00002	$0.00236	$0.00129	$0.00000	$0.00111	$0.01092
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-2 Large General TOU Secondary Service	20	CAMB	($0.00005)	$0.00147	$0.00290	$0.00002	$0.00236	$0.00091	$0.00000	$0.00079	$0.00840
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-3 Large General TOU 13.8 kV Service	21	CAMB	($0.00003)	$0.00079	$0.00156	$0.00001	$0.00236	$0.00049	$0.00000	$0.00042	$0.00560
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-4 Optional General TOU	22	CAMB	($0.00008)	$0.00135	$0.00266	$0.00001	$0.00236	$0.00083	$0.00000	$0.00072	$0.00785
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-5 Commercial Space Heating (closed)	23	CAMB	($0.00009)	$0.00141	$0.00279	$0.00002	$0.00236	$0.00087	$0.00000	$0.00075	$0.00811
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-6 Optional General TOU (Non-Demand)	24	CAMB	($0.00006)	$0.00209	$0.00411	$0.00002	$0.00236	$0.00129	$0.00000	$0.00111	$0.01092
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-1 General	29	SOUTH	($0.00008)	$0.00230	$0.00453	$0.00002	$0.00236	$0.00142	$0.00000	$0.00123	$0.01178
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-2 Medium General TOU	30	SOUTH	($0.00005)	$0.00138	$0.00273	$0.00001	$0.00236	$0.00085	$0.00000	$0.00074	$0.00802
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-3 Large General TOU	31	SOUTH	($0.00004)	$0.00091	$0.00180	$0.00001	$0.00236	$0.00056	$0.00000	$0.00049	$0.00609
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

EASTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
G-4 General Power *Last Change*	32	SOUTH	($0.00008) *2/1/18*	$0.00202 *2/1/18*	$0.00399 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00125 *2/1/18*	$0.00000 *2/1/18*	$0.00108 *2/1/18*	$0.01064 *2/1/18*
G-5 Commercial Space Heating (Closed) *Last Change*	33	SOUTH	($0.00014) *2/1/18*	$0.00245 *2/1/18*	$0.00483 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00151 *2/1/18*	$0.00000 *2/1/18*	$0.00131 *2/1/18*	$0.01235 *2/1/18*
G-6 All Electric School (Closed) *Last Change*	34	SOUTH	($0.00007) *2/1/18*	$0.00114 *2/1/18*	$0.00225 *2/1/18*	$0.00001 *2/1/18*	$0.00236 *1/1/18*	$0.00070 *2/1/18*	$0.00000 *2/1/18*	$0.00061 *2/1/18*	$0.00700 *2/1/18*
G-7 Optional General TOU *Last Change*	35	SOUTH	($0.00008) *2/1/18*	$0.00230 *2/1/18*	$0.00453 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00142 *2/1/18*	$0.00000 *2/1/18*	$0.00123 *2/1/18*	$0.01178 *2/1/18*
S-1 Street and Security Lighting *Last Change*	44	ALL	($0.00024) *2/1/18*	$0.00204 *2/1/18*	$0.00402 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00126 *2/1/18*	$0.00000 *2/1/18*	$0.00109 *2/1/18*	$0.01055 *2/1/18*
S-2 Street and Security - Customer Owned *Last Change*	45	ALL	($0.00024) *2/1/18*	$0.00204 *2/1/18*	$0.00402 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00126 *2/1/18*	$0.00000 *2/1/18*	$0.00109 *2/1/18*	$0.01055 *2/1/18*

PART C - BASIC SERVICE *
All Rates are in $/kWh across all hours and usage levels

EASTERN MASSACHUSETTS														
Sector	Rate Class	Type	Zone	01-Jan-18	01-Feb-18	01-Mar-18	01-Apr-18	01-May-18	01-Jun-18	01-Jul-18	01-Aug-18	01-Sep-18	01-Oct-18	01-Nov-18	01-Dec-18
Residential	R-1, R-2, R-3, R-4	Fixed	ALL	$0.12881	$0.12888	$0.12888	$0.12888	$0.12888	$0.12888						
		Variable	ALL	$0.14875	$0.15312	$0.12565	$0.11690	$0.11172	$0.10670						
Small C&I	All classes otherwise not listed here	Fixed	ALL	$0.12685	$0.12692	$0.12692	$0.12692	$0.12692	$0.12692						
		Variable	ALL	$0.15031	$0.15425	$0.12415	$0.11237	$0.10771	$0.10586						
Large C&I	G-2 (CAMB),G-3,T-2 (BOST)	Fixed	NEMA	$0.14632	$0.14639	$0.14639									
		Variable	NEMA	$0.15155	$0.15692	$0.13014									
Large C&I	G-2 (SOUTH),G-3,T-2 (BOST)	Fixed	SEMA	$0.11933	$0.11940	$0.11940									
		Variable	SEMA	$0.12772	$0.12891	$0.10171									
St. Lighting	S-1, S-2	Fixed	ALL	$0.12685	$0.12692	$0.12692	$0.12692	$0.12692	$0.12692						
		Variable	ALL	$0.15031	$0.15425	$0.12415	$0.11237	$0.10771	$0.10586						

* Includes the Basic Service Bad Debt Cost of $0.00130 and NSTAR Green Cost of $0.00090

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS																
												Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
R-1	7	A1/A5	ALL	Customer	$7.00		$7.00								$7.00
Residential		01/48		Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.01389	$0.01639	$0.00050	$0.10831
		32/66/68	CAPE	Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.01859	$0.02109	$0.00050	$0.11301
Last change		57/58/39			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
R-2	8	A2	ALL	Customer	$7.00		$7.00								$7.00
Residential		05		Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.00083	$0.00333	$0.00050	$0.09525
Assistance		30/37/38	CAPE	Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.00148	$0.00398	$0.00050	$0.09590
				Discount	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
R-3	9	A4/A8	ALL	Customer	$7.00		$7.00								$7.00
Residential		04/10		Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.01389	$0.01639	$0.00050	$0.09802
Space Heating		86	CAPE	Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.01859	$0.02109	$0.00050	$0.10272
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
R-4	10	A3	ALL	Customer	$7.00		$7.00								$7.00
Residential Space		07		Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.00083	$0.00333	$0.00050	$0.08496
Heating Assistance		42	CAPE	Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.00148	$0.00398	$0.00050	$0.08561
				Discount	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
									Non-Demand						
G-1	11	A9	BOST	Customer	$8.00		$8.00								$8.00
General Service				Energy (kWh) - Winter	$0.04167	$0.01907	$0.06074	$0.00000	($0.00061)	$0.02586	$0.00250	$0.00791	$0.01041	$0.00050	$0.09690
				Energy (kWh) - Summer	$0.06711	$0.01907	$0.08618	$0.00000	($0.00061)	$0.02586	$0.00250	$0.00791	$0.01041	$0.00050	$0.12234
Last change					*3/1/18*	*2/1/18*	*3/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*3/1/18*
									Demand						
		B1	BOST	Customer	$11.00		$11.00								$11.00
				Demand (>10 kW) - Winter	$0.26		$0.26			$18.19					$18.45
				1st 2000 kWh	$0.03911	$0.01907	$0.05818	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00791	$0.01041	$0.00050	$0.08779
				Next 150 hrs*kW	$0.03401	$0.01907	$0.05308	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00791	$0.01041	$0.00050	$0.08269
				remainder kWh	$0.02257	$0.01907	$0.04164	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.05194
				Demand (>10 kW) - Summer	$0.80		$0.80			$56.49					$57.29
				1st 2000 kWh	$0.06286	$0.01907	$0.08193	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00791	$0.01041	$0.00050	$0.11154
				Next 150 hrs*kW	$0.03815	$0.01907	$0.05722	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00791	$0.01041	$0.00050	$0.08683
				remainder kWh	$0.02373	$0.01907	$0.04280	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.05310
Last change					*3/1/18*	*2/1/18*	*3/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*3/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS																
												Energy Efficiency Charge (EEC)			Renewable	Total
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Energy	Delivery
G-2	12	B2	BOST	Customer	$18.00		$18.00								$18.00
General Service				Demand (>10 kW) - Winter	$9.00		$9.00			$8.73					$17.73
				1st 2000 kWh	$0.01703	$0.01265	$0.02968	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03998
				Next 150 hrs*kW	$0.01221	$0.01265	$0.02486	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03516
				remainder kWh	$0.01042	$0.01265	$0.02307	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03337
				Demand (>10 kW) - Summer	$19.30		$19.30			$23.43					$42.73
				1st 2000 kWh	$0.02651	$0.01265	$0.03916	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.04946
				Next 150 hrs*kW	$0.01386	$0.01265	$0.02651	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03681
				remainder kWh	$0.01089	$0.01265	$0.02354	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03384
				Transformer Credit / kW	($0.12)		($0.12)								($0.12)
Last change					*3/1/18*	*2/1/18*	*3/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*3/1/18*
G-3	13	B3 (NEMA)	BOST	Customer	$250.00		$250.00								$250.00
General Service		G6 (SEMA)		Demand (kW) - Winter	$8.58		$8.58			$10.28					$18.86
				Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01871
				Off Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01871
				Demand (kW) - Summer	$14.54		$14.54			$10.28					$24.82
				Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01871
				Off Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01871
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
T-1	14	B5	BOST	Customer	$10.00		$10.00								$10.00
Optional				Peak kWh - Winter	$0.06604	$0.01907	$0.08511	$0.00000	($0.00061)	$0.07833	$0.00250	$0.00791	$0.01041	$0.00050	$0.17374
General Service				Off Peak kWh - Winter	$0.01683	$0.01907	$0.03590	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.04620
TOU				Peak kWh - Summer	$0.14086	$0.01907	$0.15993	$0.00000	($0.00061)	$0.17133	$0.00250	$0.00791	$0.01041	$0.00050	$0.34156
(closed)				Off Peak kWh - Summer	$0.01857	$0.01907	$0.03764	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.04794
Last change					*3/1/18*	*2/1/18*	*3/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*3/1/18*
T-2	15	B7 (NEMA)	BOST	Customer (kW<=150)	$27.00		$27.00								$27.00
General Service		G8 (SEMA)		Customer (150<kW<=300)	$110.00		$110.00								$110.00
TOU				Customer (300<kW<=1000)	$160.00		$160.00								$160.00
				Customer (kW>1000)	$360.00		$360.00								$360.00
				Demand (kW) - Winter	$10.71		$10.71			$9.00					$19.71
				Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02295
				Off Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02295
				Demand (kW) - Summer	$18.79		$18.79			$9.00					$27.79
				Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02295
				Off Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02295
				Transformer Credit / kW	($0.12)		($0.12)								
Last change					*3/1/18*	*2/1/18*	*3/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*3/1/18*
WR	16	E1	BOST	Customer	$150.48		$150.48								$150.48
MWRA				Demand (kW)	$0.00		$0.00			$6.93					$6.93
				Energy (kWh)	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01871
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS																
												Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
SB-G3	17	C6 (NEMA)	BOST	Customer	$250.00		$250.00								$250.00
General Service		F6 (SEMA)		Standby Demand<1MW (Winter)	$4.45		$4.45								$4.45
Standby				Standby Demand=>1 MW (Winter)	$6.24		$6.24								$6.24
				Standby Demand<1MW (Summer)	$7.37		$7.37								$7.37
				Standby Demand=>1MW (Summer)	$10.34		$10.34								$10.34
				Supplemental Service	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
G-0 General	18	06	CAMB	Customer	$5.00		$5.00								$5.00
(Non-Demand)				Energy (kWh)	$0.03300	$0.01092	$0.04392	$0.00000	($0.00061)	$0.02711	$0.00250	$0.00791	$0.01041	$0.00050	$0.08133
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
G-1 General	19	02	CAMB	Customer	$8.00		$8.00								$8.00
				Demand (<=10 kW)	$3.74		$3.74			$8.67					$12.41
				Demand (> 10 kW)	$6.99		$6.99			$8.67					$15.66
				Energy (kWh)	$0.01127	$0.01092	$0.02219	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03249
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
G-2	20	62	CAMB	Customer	$97.00		$97.00								$97.00
Large General				Demand (<=100 kVA)	$4.04		$4.04			$5.46					$9.50
Secondary				Demand (> 100 kVA)	$5.01		$5.01			$11.16					$16.17
Service				Peak kWh	$0.00949	$0.00840	$0.01789	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02819
				Low A kWh	$0.00949	$0.00840	$0.01789	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02819
				Low B kWh	$0.00949	$0.00840	$0.01789	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02819
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
G-3	21	70	CAMB	Customer	$97.00		$97.00								$97.00
Large General				Demand (<=100 kVA)	$0.00		$0.00			$477.65					$477.65
TOU				Demand (> 100 kVA)	$4.31		$4.31			$8.48					$12.79
13.8 kV Service				Peak kWh	$0.00329	$0.00560	$0.00889	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01919
				Low A kWh	$0.00329	$0.00560	$0.00889	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01919
				Low B kWh	$0.00329	$0.00560	$0.00889	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01919
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
G-4	22	52	CAMB	Customer	$12.00		$12.00								$12.00
Optional General				Demand (kW)	$4.14		$4.14			$9.98					$14.12
TOU				Peak kWh	$0.01038	$0.00785	$0.01823	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02853
				Low A kWh	$0.01038	$0.00785	$0.01823	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02853
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
G-5	23	36	CAMB	Customer	$8.00		$8.00								$8.00
Commercial				Energy (<=5000 kWh)	$0.01770	$0.00811	$0.02581	$0.00000	($0.00061)	$0.02390	$0.00250	$0.00791	$0.01041	$0.00050	$0.06001
Space Heating				Energy (>5000 kWh)	$0.02326	$0.00811	$0.03137	$0.00000	($0.00061)	$0.03408	$0.00250	$0.00791	$0.01041	$0.00050	$0.07575
(closed)															
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS															
											Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
G-6	24	51	CAMB	Customer	$8.22		$8.22								$8.22
Optional General				Peak kWh	$0.06346	$0.01092	$0.07438	$0.00000	($0.00061)	$0.02711	$0.00250	$0.00791	$0.01041	$0.00050	$0.11179
TOU				Low A kWh	$0.02338	$0.01092	$0.03430	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.04460
(Non-Demand)															
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
SB-1	25	D1	CAMB	Customer	$781.00		$781.00								$781.00
Standby				Standby Demand/Replacement	$4.37		$4.37			$7.99					$12.36
				Minimum Reservation	$0.00		$0.00			$0.61					$0.61
				Replacement Energy	$0.00000	$0.00560	$0.00560	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01590
MS-1	26	D4	CAMB	Customer	$781.00		$781.00								$781.00
Maintenance				Standby Demand/Replacement	$4.37		$4.37								$4.37
				Replacement Energy	$0.00000	$0.00560	$0.00560	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01590
SS-1				Customer	$0.00										
Supplemental	27	D7		All Rate Components	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
SB-G3	28	46	CAMB	Customer	$97.00		$97.00								$97.00
General Service				Standby Demand<=1MW											
Standby				<=100 kVA	$0.00		$0.00								$0.00
				>100 kVA	$0.78		$0.78								$0.78
				Standby Demand=>1 MW											
				<=100 kVA	$0.00		$0.00								$0.00
				>100 kVA	$1.78		$1.78								$1.78
				Supplemental Demand											
				<=100 kVA	$0.00		$0.00			$477.65					$477.65
				>100 kVA	$6.36		$6.36			$8.48					$14.84
				Supplemental Energy	$0.00000	$0.00560	$0.00560	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01590
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
				Annual/Seasonal Optional											
G-1 General	29	33/23	SOUTH	Customer	$6.00		$6.00								$6.00
				Demand (<=10 kW)	$0.00		$0.00								$0.00
				Demand (>10 kW)	$4.85		$4.85								$4.85
				Energy (< =2300 kWh)	$0.04067	$0.01178	$0.05245	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00791	$0.01041	$0.00050	$0.08911
				Energy (>2300 kWh)	$0.01102	$0.01178	$0.02280	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00791	$0.01041	$0.00050	$0.05946
			CAPE	Energy (< =2300 kWh)	$0.04067	$0.01178	$0.05245	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.08650
			CAPE	Energy (>2300 kWh)	$0.01102	$0.01178	$0.02280	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.05685
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
				Seasonal											
		35	SOUTH	Cust	$6.00		$6.00								$6.00
				Demand (<=10 kW)	$0.00		$0.00								$0.00
				Demand (>10 kW)	$4.25		$4.25								$4.25
				Energy (< =1800 kWh)	$0.07506	$0.01178	$0.08684	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00791	$0.01041	$0.00050	$0.12350
				Energy (>1800 kWh)	$0.02385	$0.01178	$0.03563	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00791	$0.01041	$0.00050	$0.07229
			CAPE	Energy (< =1800 kWh)	$0.07506	$0.01178	$0.08684	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.12089
			CAPE	Energy (>1800 kWh)	$0.02385	$0.01178	$0.03563	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.06968
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	1/1/02	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS															
											Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
G-2	30	84	SOUTH	Cust	$370.00		$370.00								$370.00
Medium General				Demand (kVA)	$1.51		$1.51			$8.16					$9.67
TOU				Peak kWh	$0.01769	$0.00802	$0.02571	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00791	$0.01041	$0.00050	$0.03878
				Low A kWh	$0.01488	$0.00802	$0.02290	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00791	$0.01041	$0.00050	$0.03597
				Low B kWh	$0.00965	$0.00802	$0.01767	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00791	$0.01041	$0.00050	$0.03074
			CAPE	Peak kWh	$0.01769	$0.00802	$0.02571	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00530	$0.00780	$0.00050	$0.03617
			CAPE	Low A kWh	$0.01488	$0.00802	$0.02290	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00530	$0.00780	$0.00050	$0.03336
			CAPE	Low B kWh	$0.00965	$0.00802	$0.01767	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00530	$0.00780	$0.00050	$0.02813
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
G-3	31	24	SOUTH	Customer	$930.00		$930.00								$930.00
Large General				Demand (kVA)	$0.87		$0.87			$8.22					$9.09
TOU				Energy (kWh) - Peak	$0.01242	$0.00609	$0.01851	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02881
				Energy (kWh) - Low A	$0.01142	$0.00609	$0.01751	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02781
				Energy (kWh) - Low B	$0.00791	$0.00609	$0.01400	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02430
			CAPE	Energy (kWh) - Peak	$0.01242	$0.00609	$0.01851	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.02620
			CAPE	Energy (kWh) - Low A	$0.01142	$0.00609	$0.01751	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.02520
			CAPE	Energy (kWh) - Low B	$0.00791	$0.00609	$0.01400	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.02169
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	1/1/02	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
G-4	32	41	SOUTH	Customer	$6.00		$6.00								$6.00
General Power				Demand (kW)	$1.74		$1.74			$2.69					$4.43
				Energy (kWh)	$0.01998	$0.01064	$0.03062	$0.00000	($0.00061)	$0.00326	$0.00250	$0.00791	$0.01041	$0.00050	$0.04418
			CAPE	Energy (kWh)	$0.01998	$0.01064	$0.03062	$0.00000	($0.00061)	$0.00326	$0.00250	$0.00530	$0.00780	$0.00050	$0.04157
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
G-5	33	88	SOUTH	Customer	$6.00		$6.00								$6.00
Commercial				Energy (kWh)	$0.03563	$0.01235	$0.04798	$0.00000	($0.00061)	$0.03267	$0.00250	$0.00791	$0.01041	$0.00050	$0.09095
Space Heating			CAPE	Energy (kWh)	$0.03563	$0.01235	$0.04798	$0.00000	($0.00061)	$0.03267	$0.00250	$0.00530	$0.00780	$0.00050	$0.08834
(Closed)															
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
G-6	34	22	SOUTH	Customer	$30.00		$30.00								$30.00
All Electric School				Energy (kWh)	$0.01633	$0.00700	$0.02333	$0.00000	($0.00061)	$0.02666	$0.00250	$0.00791	$0.01041	$0.00050	$0.06029
(Closed)			CAPE	Energy (kWh)	$0.01633	$0.00700	$0.02333	$0.00000	($0.00061)	$0.02666	$0.00250	$0.00530	$0.00780	$0.00050	$0.05768
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
				Annual											
G-7	35	55	SOUTH	Customer	$10.00		$10.00								$10.00
Optional General				Demand (kW)	$3.33		$3.33			$10.63					$13.96
TOU				Peak kWh	$0.02290	$0.01178	$0.03468	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.04498
				Low A kWh	$0.01604	$0.01178	$0.02782	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03812
			CAPE	Peak kWh	$0.02290	$0.01178	$0.03468	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.04237
			CAPE	Low A kWh	$0.01604	$0.01178	$0.02782	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.03551
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
				Seasonal											
		31	SOUTH	Customer	$10.00		$10.00								$10.00
				Demand (kW)	$3.36		$3.36			$4.96					$8.32
				Peak kWh	$0.04453	$0.01178	$0.05631	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.06661
				Low A kWh	$0.03745	$0.01178	$0.04923	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.05953
			CAPE	Peak kWh	$0.04453	$0.01178	$0.05631	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.06400
			CAPE	Low A kWh	$0.03745	$0.01178	$0.04923	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.05692
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS															
											Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
S-1	44	C1/C3	ALL	Fixture Charge	Per Rate Schedule		Per Rate Schedule								Per Rate Schedule
Street and Security Lighting		19/80		Energy (kWh)		$0.01055		$0.00000	($0.00061)	$0.01258	$0.00250	$0.00791	$0.01041	$0.00050	
		79/81	CAPE	Energy (kWh)		$0.01055		$0.00000	($0.00061)	$0.01258	$0.00250	$0.00530	$0.00780	$0.00050	
Last Change					*3/1/18*	*2/1/18*	*3/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*3/1/18*
S-2	45	C2/C4	ALL	Customer	$6.48		$6.48								$6.48
Street and Security -		83/89		Energy (kWh)	$0.02467	$0.01055	$0.03522	$0.00000	($0.00061)	$0.01258	$0.00250	$0.00791	$0.01041	$0.00050	$0.05810
Customer Owned		82/96	CAPE	Energy (kWh)	$0.02467	$0.01055	$0.03522	$0.00000	($0.00061)	$0.01258	$0.00250	$0.00530	$0.00780	$0.00050	$0.05549
Last Change					*3/1/18*	*2/1/18*	*3/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*3/1/18*

(2) Transmission Charge for Rate R-2 customers in the Boston service area is $0.03057 from February 1, 2018 through December 31, 2018

Summer Months - June thru September
Winter Months - October thru May

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

EASTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
R-1 Residential *Last change*	7	ALL	($0.00011) *2/1/18*	$0.00375 *2/1/18*	$0.00738 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00231 *2/1/18*	$0.00000 *2/1/18*	$0.00200 *2/1/18*	$0.01773 *2/1/18*
R-2 Residential Assistance *Last change*	8	ALL	($0.00011) *2/1/18*	$0.00375 *2/1/18*	$0.00738 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00231 *2/1/18*	$0.00000 *2/1/18*	$0.00200 *2/1/18*	$0.01773 *2/1/18*
R-3 Residential Space Heating *Last change*	9	ALL	($0.00010) *2/1/18*	$0.00295 *2/1/18*	$0.00580 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00182 *2/1/18*	$0.00000 *2/1/18*	$0.00157 *2/1/18*	$0.01443 *2/1/18*
R-4 Residential Space Heating Assistance *Last change*	10	ALL	($0.00010) *2/1/18*	$0.00295 *2/1/18*	$0.00580 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00182 *2/1/18*	$0.00000 *2/1/18*	$0.00157 *2/1/18*	$0.01443 *2/1/18*
G-1 General Service *Last change*	11	BOST	($0.00011) *2/1/18*	$0.00407 *2/1/18*	$0.00803 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00251 *2/1/18*	$0.00000 *2/1/18*	$0.00217 *2/1/18*	$0.01907 *2/1/18*
G-2 General Service *Last change*	12	BOST	($0.00005) *2/1/18*	$0.00250 *2/1/18*	$0.00493 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00154 *2/1/18*	$0.00000 *2/1/18*	$0.00134 *2/1/18*	$0.01265 *2/1/18*
G-3 General Service *Last change*	13	BOST	($0.00003) *2/1/18*	$0.00147 *2/1/18*	$0.00290 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00091 *2/1/18*	$0.00000 *2/1/18*	$0.00078 *2/1/18*	$0.00841 *2/1/18*
T-1 General Service Optional Time-of-Use *Last change*	14	BOST	($0.00011) *2/1/18*	$0.00407 *2/1/18*	$0.00803 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00251 *2/1/18*	$0.00000 *2/1/18*	$0.00217 *2/1/18*	$0.01907 *2/1/18*
T-2 General Service Time-of-Use *Last change*	15	BOST	($0.00005) *2/1/18*	$0.00250 *2/1/18*	$0.00493 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00154 *2/1/18*	$0.00000 *2/1/18*	$0.00134 *2/1/18*	$0.01265 *2/1/18*
WR MWRA *Last Change*	16	BOST	($0.00003) *2/1/18*	$0.00147 *2/1/18*	$0.00290 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00091 *2/1/18*	$0.00000 *2/1/18*	$0.00078 *2/1/18*	$0.00841 *2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

EASTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
G-0 General (Non-Demand)	18	CAMB	($0.00006)	$0.00209	$0.00411	$0.00002	$0.00236	$0.00129	$0.00000	$0.00111	$0.01092
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-1 General	19	CAMB	($0.00006)	$0.00209	$0.00411	$0.00002	$0.00236	$0.00129	$0.00000	$0.00111	$0.01092
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-2 Large General TOU Secondary Service	20	CAMB	($0.00005)	$0.00147	$0.00290	$0.00002	$0.00236	$0.00091	$0.00000	$0.00079	$0.00840
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-3 Large General TOU 13.8 kV Service	21	CAMB	($0.00003)	$0.00079	$0.00156	$0.00001	$0.00236	$0.00049	$0.00000	$0.00042	$0.00560
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-4 Optional General TOU	22	CAMB	($0.00008)	$0.00135	$0.00266	$0.00001	$0.00236	$0.00083	$0.00000	$0.00072	$0.00785
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-5 Commercial Space Heating (closed)	23	CAMB	($0.00009)	$0.00141	$0.00279	$0.00002	$0.00236	$0.00087	$0.00000	$0.00075	$0.00811
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-6 Optional General TOU (Non-Demand)	24	CAMB	($0.00006)	$0.00209	$0.00411	$0.00002	$0.00236	$0.00129	$0.00000	$0.00111	$0.01092
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-1 General	29	SOUTH	($0.00008)	$0.00230	$0.00453	$0.00002	$0.00236	$0.00142	$0.00000	$0.00123	$0.01178
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-2 Medium General TOU	30	SOUTH	($0.00005)	$0.00138	$0.00273	$0.00001	$0.00236	$0.00085	$0.00000	$0.00074	$0.00802
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-3 Large General TOU	31	SOUTH	($0.00004)	$0.00091	$0.00180	$0.00001	$0.00236	$0.00056	$0.00000	$0.00049	$0.00609
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

EASTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
G-4 General Power *Last Change*	32	SOUTH	($0.00008) *2/1/18*	$0.00202 *2/1/18*	$0.00399 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00125 *2/1/18*	$0.00000 *2/1/18*	$0.00108 *2/1/18*	$0.01064 *2/1/18*
G-5 Commercial Space Heating (Closed) *Last Change*	33	SOUTH	($0.00014) *2/1/18*	$0.00245 *2/1/18*	$0.00483 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00151 *2/1/18*	$0.00000 *2/1/18*	$0.00131 *2/1/18*	$0.01235 *2/1/18*
G-6 All Electric School (Closed) *Last Change*	34	SOUTH	($0.00007) *2/1/18*	$0.00114 *2/1/18*	$0.00225 *2/1/18*	$0.00001 *2/1/18*	$0.00236 *1/1/18*	$0.00070 *2/1/18*	$0.00000 *2/1/18*	$0.00061 *2/1/18*	$0.00700 *2/1/18*
G-7 Optional General TOU *Last Change*	35	SOUTH	($0.00008) *2/1/18*	$0.00230 *2/1/18*	$0.00453 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00142 *2/1/18*	$0.00000 *2/1/18*	$0.00123 *2/1/18*	$0.01178 *2/1/18*
S-1 Street and Security Lighting *Last Change*	44	ALL	($0.00024) *2/1/18*	$0.00204 *2/1/18*	$0.00402 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00126 *2/1/18*	$0.00000 *2/1/18*	$0.00109 *2/1/18*	$0.01055 *2/1/18*
S-2 Street and Security - Customer Owned *Last Change*	45	ALL	($0.00024) *2/1/18*	$0.00204 *2/1/18*	$0.00402 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00126 *2/1/18*	$0.00000 *2/1/18*	$0.00109 *2/1/18*	$0.01055 *2/1/18*

PART C - BASIC SERVICE *
All Rates are in $/kWh across all hours and usage levels

EASTERN MASSACHUSETTS														
Sector	Rate Class	Type	Zone	01-Jan-18	01-Feb-18	01-Mar-18	01-Apr-18	01-May-18	01-Jun-18	01-Jul-18	01-Aug-18	01-Sep-18	01-Oct-18	01-Nov-18	01-Dec-18
Residential	R-1, R-2, R-3, R-4	Fixed	ALL	$0.12881	$0.12888	$0.12888	$0.12888	$0.12888	$0.12888						
		Variable	ALL	$0.14875	$0.15312	$0.12565	$0.11690	$0.11172	$0.10670						
Small C&I	All classes otherwise not listed here	Fixed	ALL	$0.12685	$0.12692	$0.12692	$0.12692	$0.12692	$0.12692						
		Variable	ALL	$0.15031	$0.15425	$0.12415	$0.11237	$0.10771	$0.10586						
Large C&I	G-2 (CAMB),G-3,T-2 (BOST)	Fixed	NEMA	$0.14632	$0.14639	$0.14639									
		Variable	NEMA	$0.15155	$0.15692	$0.13014									
Large C&I	G-2 (SOUTH),G-3,T-2 (BOST)	Fixed	SEMA	$0.11933	$0.11940	$0.11940									
		Variable	SEMA	$0.12772	$0.12891	$0.10171									
St. Lighting	S-1, S-2	Fixed	ALL	$0.12685	$0.12692	$0.12692	$0.12692	$0.12692	$0.12692						
		Variable	ALL	$0.15031	$0.15425	$0.12415	$0.11237	$0.10771	$0.10586						

* Includes the Basic Service Bad Debt Cost of $0.00130 and NSTAR Green Cost of $0.00090

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS															
											Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
R-1	7	A1/A5	ALL	Customer	$7.00		$7.00								$7.00
Residential		01/48		Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.01389	$0.01639	$0.00050	$0.10831
		32/66/68	CAPE	Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.01859	$0.02109	$0.00050	$0.11301
Last change		57/58/39			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
R-2	8	A2	ALL	Customer	$7.00		$7.00								$7.00
Residential		05		Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.00083	$0.00333	$0.00050	$0.09525
Assistance		30/37/38	CAPE	Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.00148	$0.00398	$0.00050	$0.09590
				Discount	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
R-3	9	A4/A8	ALL	Customer	$7.00		$7.00								$7.00
Residential		04/10		Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.01389	$0.01639	$0.00050	$0.09802
Space Heating		86	CAPE	Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.01859	$0.02109	$0.00050	$0.10272
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
R-4	10	A3	ALL	Customer	$7.00		$7.00								$7.00
Residential Space		07		Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.00083	$0.00333	$0.00050	$0.08496
Heating Assistance		42	CAPE	Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.00148	$0.00398	$0.00050	$0.08561
				Discount	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
									Non-Demand						
G-1	11	A9	BOST	Customer	$8.00		$8.00								$8.00
General Service				Energy (kWh) - Winter	$0.04167	$0.01907	$0.06074	$0.00000	($0.00061)	$0.02586	$0.00250	$0.00791	$0.01041	$0.00050	$0.09690
				Energy (kWh) - Summer	$0.06711	$0.01907	$0.08618	$0.00000	($0.00061)	$0.02586	$0.00250	$0.00791	$0.01041	$0.00050	$0.12234
Last change					*3/1/18*	*2/1/18*	*3/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*3/1/18*
									Demand						
		B1	BOST	Customer	$11.00		$11.00								$11.00
				Demand (>10 kW) - Winter	$0.26		$0.26			$18.19					$18.45
				1st 2000 kWh	$0.03911	$0.01907	$0.05818	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00791	$0.01041	$0.00050	$0.08779
				Next 150 hrs*kW	$0.03401	$0.01907	$0.05308	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00791	$0.01041	$0.00050	$0.08269
				remainder kWh	$0.02257	$0.01907	$0.04164	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.05194
				Demand (>10 kW) - Summer	$0.80		$0.80			$56.49					$57.29
				1st 2000 kWh	$0.06286	$0.01907	$0.08193	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00791	$0.01041	$0.00050	$0.11154
				Next 150 hrs*kW	$0.03815	$0.01907	$0.05722	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00791	$0.01041	$0.00050	$0.08683
				remainder kWh	$0.02373	$0.01907	$0.04280	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.05310
Last change					*3/1/18*	*2/1/18*	*3/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*3/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS

Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	Energy Efficiency Charge (EEC) System Benefits	EEC Recon. Factor	EEC Total EEC	Renewable Energy	Total Delivery
G-2	12	B2	BOST	Customer	$18.00		$18.00								$18.00
General Service				Demand (>10 kW) - Winter	$9.00		$9.00			$8.73					$17.73
				1st 2000 kWh	$0.01703	$0.01265	$0.02968	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03998
				Next 150 hrs*kW	$0.01221	$0.01265	$0.02486	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03516
				remainder kWh	$0.01042	$0.01265	$0.02307	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03337
				Demand (>10 kW) - Summer	$19.30		$19.30			$23.43					$42.73
				1st 2000 kWh	$0.02651	$0.01265	$0.03916	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.04946
				Next 150 hrs*kW	$0.01386	$0.01265	$0.02651	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03681
				remainder kWh	$0.01089	$0.01265	$0.02354	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03384
				Transformer Credit / kW	($0.12)		($0.12)								($0.12)
Last change					*3/1/18*	*2/1/18*	*3/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*3/1/18*
G-3	13	B3 (NEMA)	BOST	Customer	$250.00		$250.00								$250.00
General Service		G6 (SEMA)		Demand (kW) - Winter	$8.58		$8.58			$10.28					$18.86
				Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01871
				Off Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01871
				Demand (kW) - Summer	$14.54		$14.54			$10.28					$24.82
				Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01871
				Off Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01871
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
T-1	14	B5	BOST	Customer	$10.00		$10.00								$10.00
Optional				Peak kWh - Winter	$0.06604	$0.01907	$0.08511	$0.00000	($0.00061)	$0.07833	$0.00250	$0.00791	$0.01041	$0.00050	$0.17374
General Service				Off Peak kWh - Winter	$0.01683	$0.01907	$0.03590	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.04620
TOU				Peak kWh - Summer	$0.14086	$0.01907	$0.15993	$0.00000	($0.00061)	$0.17133	$0.00250	$0.00791	$0.01041	$0.00050	$0.34156
(closed)				Off Peak kWh - Summer	$0.01857	$0.01907	$0.03764	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.04794
Last change					*3/1/18*	*2/1/18*	*3/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*3/1/18*
T-2	15	B7 (NEMA)	BOST	Customer (kW<=150)	$27.00		$27.00								$27.00
General Service		G8 (SEMA)		Customer (150<kW<=300)	$110.00		$110.00								$110.00
TOU				Customer (300<kW<=1000)	$160.00		$160.00								$160.00
				Customer (kW>1000)	$360.00		$360.00								$360.00
				Demand (kW) - Winter	$10.71		$10.71			$9.00					$19.71
				Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02295
				Off Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02295
				Demand (kW) - Summer	$18.79		$18.79			$9.00					$27.79
				Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02295
				Off Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02295
				Transformer Credit / kW	($0.12)		($0.12)								
Last change					*3/1/18*	*2/1/18*	*3/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*3/1/18*
WR	16	E1	BOST	Customer	$150.48		$150.48								$150.48
MWRA				Demand (kW)	$0.00		$0.00			$6.93					$6.93
				Energy (kWh)	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01871
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS															
											Energy Efficiency Charge (EEC)			Renewable	Total
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Energy	Delivery
SB-G3 General Service Standby *Last change*	17	C6 (NEMA) F6 (SEMA)	BOST	Customer Standby Demand<1MW (Winter) Standby Demand=>1 MW (Winter) Standby Demand<1MW (Summer) Standby Demand=>1MW (Summer) Supplemental Service	$250.00 $4.45 $6.24 $7.37 $10.34 per G-3 *2/1/18*	 per G-3 *2/1/18*	$250.00 $4.45 $6.24 $7.37 $10.34 per G-3 *2/1/18*	 per G-3 *2/1/18*	 per G-3 *2/1/18*	 per G-3 *2/1/18*	 per G-3 *1/1/02*	 per G-3 *7/1/17*	 per G-3 *7/1/17*	 per G-3 *1/1/03*	$250.00 $4.45 $6.24 $7.37 $10.34 per G-3 *2/1/18*
G-0 General (Non-Demand) *Last Change*	18	06	CAMB	Customer Energy (kWh)	$5.00 $0.03300 *2/1/18*	 $0.01092 *2/1/18*	$5.00 $0.04392 *2/1/18*	 $0.00000 *2/1/18*	 ($0.00061) *2/1/18*	 $0.02711 *2/1/18*	 $0.00250 *1/1/02*	 $0.00791 *7/1/17*	 $0.01041 *7/1/17*	 $0.00050 *1/1/03*	$5.00 $0.08133 *2/1/18*
G-1 General *Last Change*	19	02	CAMB	Customer Demand (<=10 kW) Demand (> 10 kW) Energy (kWh)	$8.00 $3.74 $6.99 $0.01127 *2/1/18*	 $0.01092 *2/1/18*	$8.00 $3.74 $6.99 $0.02219 *2/1/18*	 $0.00000 *2/1/18*	 ($0.00061) *2/1/18*	 $8.67 $8.67 $0.00000 *2/1/18*	 $0.00250 *1/1/02*	 $0.00791 *7/1/17*	 $0.01041 *7/1/17*	 $0.00050 *1/1/03*	$8.00 $12.41 $15.66 $0.03249 *2/1/18*
G-2 Large General Secondary Service *Last Change*	20	62	CAMB	Customer Demand (<=100 kVA) Demand (> 100 kVA) Peak kWh Low A kWh Low B kWh	$97.00 $4.04 $5.01 $0.00949 $0.00949 $0.00949 *2/1/18*	 $0.00840 $0.00840 $0.00840 *2/1/18*	$97.00 $4.04 $5.01 $0.01789 $0.01789 $0.01789 *2/1/18*	 $0.00000 $0.00000 $0.00000 *2/1/18*	 ($0.00061) ($0.00061) ($0.00061) *2/1/18*	 $5.46 $11.16 $0.00000 $0.00000 $0.00000 *2/1/18*	 $0.00250 $0.00250 $0.00250 *1/1/02*	 $0.00791 $0.00791 $0.00791 *7/1/17*	 $0.01041 $0.01041 $0.01041 *7/1/17*	 $0.00050 $0.00050 $0.00050 *1/1/03*	$97.00 $9.50 $16.17 $0.02819 $0.02819 $0.02819 *2/1/18*
G-3 Large General TOU 13.8 kV Service *Last Change*	21	70	CAMB	Customer Demand (<=100 kVA) Demand (> 100 kVA) Peak kWh Low A kWh Low B kWh	$97.00 $0.00 $4.31 $0.00329 $0.00329 $0.00329 *2/1/18*	 $0.00560 $0.00560 $0.00560 *2/1/18*	$97.00 $0.00 $4.31 $0.00889 $0.00889 $0.00889 *2/1/18*	 $0.00000 $0.00000 $0.00000 *2/1/18*	 ($0.00061) ($0.00061) ($0.00061) *2/1/18*	 $477.65 $8.48 $0.00000 $0.00000 $0.00000 *2/1/18*	 $0.00250 $0.00250 $0.00250 *1/1/02*	 $0.00791 $0.00791 $0.00791 *7/1/17*	 $0.01041 $0.01041 $0.01041 *7/1/17*	 $0.00050 $0.00050 $0.00050 *1/1/03*	$97.00 $477.65 $12.79 $0.01919 $0.01919 $0.01919 *2/1/18*
G-4 Optional General TOU *Last Change*	22	52	CAMB	Customer Demand (kW) Peak kWh Low A kWh	$12.00 $4.14 $0.01038 $0.01038 *2/1/18*	 $0.00785 $0.00785 *2/1/18*	$12.00 $4.14 $0.01823 $0.01823 *2/1/18*	 $0.00000 $0.00000 *2/1/18*	 ($0.00061) ($0.00061) *2/1/18*	 $9.98 $0.00000 $0.00000 *2/1/18*	 $0.00250 $0.00250 *1/1/02*	 $0.00791 $0.00791 *7/1/17*	 $0.01041 $0.01041 *7/1/17*	 $0.00050 $0.00050 *1/1/03*	$12.00 $14.12 $0.02853 $0.02853 *2/1/18*
G-5 Commercial Space Heating (closed) *Last Change*	23	36	CAMB	Customer Energy (<=5000 kWh) Energy (>5000 kWh)	$8.00 $0.01770 $0.02326 *2/1/18*	 $0.00811 $0.00811 *2/1/18*	$8.00 $0.02581 $0.03137 *2/1/18*	 $0.00000 $0.00000 *2/1/18*	 ($0.00061) ($0.00061) *2/1/18*	 $0.02390 $0.03408 *2/1/18*	 $0.00250 $0.00250 *1/1/02*	 $0.00791 $0.00791 *7/1/17*	 $0.01041 $0.01041 *7/1/17*	 $0.00050 $0.00050 *1/1/03*	$8.00 $0.06001 $0.07575 *2/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS																
												Energy Efficiency Charge (EEC)			Renewable	Total
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Energy	Delivery
G-6	24	51	CAMB	Customer	$8.22		$8.22								$8.22
Optional General				Peak kWh	$0.06346	$0.01092	$0.07438	$0.00000	($0.00061)	$0.02711	$0.00250	$0.00791	$0.01041	$0.00050	$0.11179
TOU				Low A kWh	$0.02338	$0.01092	$0.03430	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.04460
(Non-Demand)															
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
SB-1	25	D1	CAMB	Customer	$781.00		$781.00								$781.00
Standby				Standby Demand/Replacement	$4.37		$4.37			$7.99					$12.36
				Minimum Reservation	$0.00		$0.00			$0.61					$0.61
				Replacement Energy	$0.00000	$0.00560	$0.00560	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01590
MS-1	26	D4	CAMB	Customer	$781.00		$781.00								$781.00
Maintenance				Standby Demand/Replacement	$4.37		$4.37								$4.37
				Replacement Energy	$0.00000	$0.00560	$0.00560	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01590
SS-1				Customer	$0.00										
Supplemental	27	D7		All Rate Components	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
SB-G3	28	46	CAMB	Customer	$97.00		$97.00								$97.00
General Service				Standby Demand<=1MW											
Standby				<=100 kVA	$0.00		$0.00								$0.00
				>100 kVA	$0.78		$0.78								$0.78
				Standby Demand=>1 MW											
				<=100 kVA	$0.00		$0.00								$0.00
				>100 kVA	$1.78		$1.78								$1.78
				Supplemental Demand											
				<=100 kVA	$0.00		$0.00			$477.65					$477.65
				>100 kVA	$6.36		$6.36			$8.48					$14.84
				Supplemental Energy	$0.00000	$0.00560	$0.00560	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.01590
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
				Annual/Seasonal Optional											
G-1 General	29	33/23	SOUTH	Customer	$6.00		$6.00								$6.00
				Demand (<=10 kW)	$0.00		$0.00								$0.00
				Demand (>10 kW)	$4.85		$4.85								$4.85
				Energy (< =2300 kWh)	$0.04067	$0.01178	$0.05245	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00791	$0.01041	$0.00050	$0.08911
				Energy (>2300 kWh)	$0.01102	$0.01178	$0.02280	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00791	$0.01041	$0.00050	$0.05946
			CAPE	Energy (< =2300 kWh)	$0.04067	$0.01178	$0.05245	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.08650
			CAPE	Energy (>2300 kWh)	$0.01102	$0.01178	$0.02280	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.05685
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
				Seasonal											
		35	SOUTH	Cust	$6.00		$6.00								$6.00
				Demand (<=10 kW)	$0.00		$0.00								$0.00
				Demand (>10 kW)	$4.25		$4.25								$4.25
				Energy (< =1800 kWh)	$0.07506	$0.01178	$0.08684	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00791	$0.01041	$0.00050	$0.12350
				Energy (>1800 kWh)	$0.02385	$0.01178	$0.03563	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00791	$0.01041	$0.00050	$0.07229
			CAPE	Energy (< =1800 kWh)	$0.07506	$0.01178	$0.08684	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.12089
			CAPE	Energy (>1800 kWh)	$0.02385	$0.01178	$0.03563	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.06968
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	1/1/02	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS																
													Energy Efficiency Charge (EEC)			Renewable	Total
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Energy	Delivery
G-2	30	84	SOUTH	Cust	$370.00		$370.00								$370.00
Medium General				Demand (kVA)	$1.51		$1.51			$8.16					$9.67
TOU				Peak kWh	$0.01769	$0.00802	$0.02571	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00791	$0.01041	$0.00050	$0.03878
				Low A kWh	$0.01488	$0.00802	$0.02290	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00791	$0.01041	$0.00050	$0.03597
				Low B kWh	$0.00965	$0.00802	$0.01767	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00791	$0.01041	$0.00050	$0.03074
			CAPE	Peak kWh	$0.01769	$0.00802	$0.02571	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00530	$0.00780	$0.00050	$0.03617
			CAPE	Low A kWh	$0.01488	$0.00802	$0.02290	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00530	$0.00780	$0.00050	$0.03336
			CAPE	Low B kWh	$0.00965	$0.00802	$0.01767	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00530	$0.00780	$0.00050	$0.02813
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
G-3	31	24	SOUTH	Customer	$930.00		$930.00								$930.00
Large General				Demand (kVA)	$0.87		$0.87			$8.22					$9.09
TOU				Energy (kWh) - Peak	$0.01242	$0.00609	$0.01851	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02881
				Energy (kWh) - Low A	$0.01142	$0.00609	$0.01751	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02781
				Energy (kWh) - Low B	$0.00791	$0.00609	$0.01400	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.02430
			CAPE	Energy (kWh) - Peak	$0.01242	$0.00609	$0.01851	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.02620
			CAPE	Energy (kWh) - Low A	$0.01142	$0.00609	$0.01751	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.02520
			CAPE	Energy (kWh) - Low B	$0.00791	$0.00609	$0.01400	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.02169
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	1/1/02	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
G-4	32	41	SOUTH	Customer	$6.00		$6.00								$6.00
General Power				Demand (kW)	$1.74		$1.74			$2.69					$4.43
				Energy (kWh)	$0.01998	$0.01064	$0.03062	$0.00000	($0.00061)	$0.00326	$0.00250	$0.00791	$0.01041	$0.00050	$0.04418
			CAPE	Energy (kWh)	$0.01998	$0.01064	$0.03062	$0.00000	($0.00061)	$0.00326	$0.00250	$0.00530	$0.00780	$0.00050	$0.04157
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
G-5	33	88	SOUTH	Customer	$6.00		$6.00								$6.00
Commercial				Energy (kWh)	$0.03563	$0.01235	$0.04798	$0.00000	($0.00061)	$0.03267	$0.00250	$0.00791	$0.01041	$0.00050	$0.09095
Space Heating			CAPE	Energy (kWh)	$0.03563	$0.01235	$0.04798	$0.00000	($0.00061)	$0.03267	$0.00250	$0.00530	$0.00780	$0.00050	$0.08834
(Closed)															
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
G-6	34	22	SOUTH	Customer	$30.00		$30.00								$30.00
All Electric School				Energy (kWh)	$0.01633	$0.00700	$0.02333	$0.00000	($0.00061)	$0.02666	$0.00250	$0.00791	$0.01041	$0.00050	$0.06029
(Closed)			CAPE	Energy (kWh)	$0.01633	$0.00700	$0.02333	$0.00000	($0.00061)	$0.02666	$0.00250	$0.00530	$0.00780	$0.00050	$0.05768
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
									Annual						
G-7	35	55	SOUTH	Customer	$10.00		$10.00								$10.00
Optional General				Demand (kW)	$3.33		$3.33			$10.63					$13.96
TOU				Peak kWh	$0.02290	$0.01178	$0.03468	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.04498
				Low A kWh	$0.01604	$0.01178	$0.02782	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.03812
			CAPE	Peak kWh	$0.02290	$0.01178	$0.03468	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.04237
			CAPE	Low A kWh	$0.01604	$0.01178	$0.02782	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.03551
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*
									Seasonal						
		31	SOUTH	Customer	$10.00		$10.00								$10.00
				Demand (kW)	$3.36		$3.36			$4.96					$8.32
				Peak kWh	$0.04453	$0.01178	$0.05631	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.06661
				Low A kWh	$0.03745	$0.01178	$0.04923	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00791	$0.01041	$0.00050	$0.05953
			CAPE	Peak kWh	$0.04453	$0.01178	$0.05631	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.06400
			CAPE	Low A kWh	$0.03745	$0.01178	$0.04923	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.05692
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*2/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS															
											Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
S-1	44	C1/C3	ALL	Fixture Charge	Per Rate Schedule		Per Rate Schedule								Per Rate Schedule
Street and		19/80		Energy (kWh)		$0.01055		$0.00000	($0.00061)	$0.01258	$0.00250	$0.00791	$0.01041	$0.00050	
Security Lighting		79/81	CAPE	Energy (kWh)		$0.01055		$0.00000	($0.00061)	$0.01258	$0.00250	$0.00530	$0.00780	$0.00050	
Last Change					*3/1/18*	*2/1/18*	*3/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*3/1/18*
S-2	45	C2/C4	ALL	Customer	$6.48		$6.48								$6.48
Street and Security -		83/89		Energy (kWh)	$0.02467	$0.01055	$0.03522	$0.00000	($0.00061)	$0.01258	$0.00250	$0.00791	$0.01041	$0.00050	$0.05810
Customer Owned		82/96	CAPE	Energy (kWh)	$0.02467	$0.01055	$0.03522	$0.00000	($0.00061)	$0.01258	$0.00250	$0.00530	$0.00780	$0.00050	$0.05549
Last Change					*3/1/18*	*2/1/18*	*3/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*1/1/18*	*1/1/18*	*1/1/03*	*3/1/18*

(2) Transmission Charge for Rate R-2 customers in the Boston service area is $0.03057 from February 1, 2018 through December 31, 2018

Summer Months - June thru September
Winter Months - October thru May

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

EASTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
R-1 Residential *Last change*	7	ALL	($0.00011) *2/1/18*	$0.00375 *2/1/18*	$0.00738 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00231 *2/1/18*	$0.00000 *2/1/18*	$0.00200 *2/1/18*	$0.01773 *2/1/18*
R-2 Residential Assistance *Last change*	8	ALL	($0.00011) *2/1/18*	$0.00375 *2/1/18*	$0.00738 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00231 *2/1/18*	$0.00000 *2/1/18*	$0.00200 *2/1/18*	$0.01773 *2/1/18*
R-3 Residential Space Heating *Last change*	9	ALL	($0.00010) *2/1/18*	$0.00295 *2/1/18*	$0.00580 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00182 *2/1/18*	$0.00000 *2/1/18*	$0.00157 *2/1/18*	$0.01443 *2/1/18*
R-4 Residential Space Heating Assistance *Last change*	10	ALL	($0.00010) *2/1/18*	$0.00295 *2/1/18*	$0.00580 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00182 *2/1/18*	$0.00000 *2/1/18*	$0.00157 *2/1/18*	$0.01443 *2/1/18*
G-1 General Service *Last change*	11	BOST	($0.00011) *2/1/18*	$0.00407 *2/1/18*	$0.00803 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00251 *2/1/18*	$0.00000 *2/1/18*	$0.00217 *2/1/18*	$0.01907 *2/1/18*
G-2 General Service *Last change*	12	BOST	($0.00005) *2/1/18*	$0.00250 *2/1/18*	$0.00493 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00154 *2/1/18*	$0.00000 *2/1/18*	$0.00134 *2/1/18*	$0.01265 *2/1/18*
G-3 General Service *Last change*	13	BOST	($0.00003) *2/1/18*	$0.00147 *2/1/18*	$0.00290 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00091 *2/1/18*	$0.00000 *2/1/18*	$0.00078 *2/1/18*	$0.00841 *2/1/18*
T-1 General Service Optional Time-of-Use *Last change*	14	BOST	($0.00011) *2/1/18*	$0.00407 *2/1/18*	$0.00803 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00251 *2/1/18*	$0.00000 *2/1/18*	$0.00217 *2/1/18*	$0.01907 *2/1/18*
T-2 General Service Time-of-Use *Last change*	15	BOST	($0.00005) *2/1/18*	$0.00250 *2/1/18*	$0.00493 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00154 *2/1/18*	$0.00000 *2/1/18*	$0.00134 *2/1/18*	$0.01265 *2/1/18*
WR MWRA *Last Change*	16	BOST	($0.00003) *2/1/18*	$0.00147 *2/1/18*	$0.00290 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00091 *2/1/18*	$0.00000 *2/1/18*	$0.00078 *2/1/18*	$0.00841 *2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

EASTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
G-0 General (Non-Demand) *Last Change*	18	CAMB	($0.00006) *2/1/18*	$0.00209 *2/1/18*	$0.00411 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00129 *2/1/18*	$0.00000 *2/1/18*	$0.00111 *2/1/18*	$0.01092 *2/1/18*
G-1 General *Last Change*	19	CAMB	($0.00006) *2/1/18*	$0.00209 *2/1/18*	$0.00411 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00129 *2/1/18*	$0.00000 *2/1/18*	$0.00111 *2/1/18*	$0.01092 *2/1/18*
G-2 Large General TOU Secondary Service *Last Change*	20	CAMB	($0.00005) *2/1/18*	$0.00147 *2/1/18*	$0.00290 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00091 *2/1/18*	$0.00000 *2/1/18*	$0.00079 *2/1/18*	$0.00840 *2/1/18*
G-3 Large General TOU 13.8 kV Service *Last Change*	21	CAMB	($0.00003) *2/1/18*	$0.00079 *2/1/18*	$0.00156 *2/1/18*	$0.00001 *2/1/18*	$0.00236 *1/1/18*	$0.00049 *2/1/18*	$0.00000 *2/1/18*	$0.00042 *2/1/18*	$0.00560 *2/1/18*
G-4 Optional General TOU *Last Change*	22	CAMB	($0.00008) *2/1/18*	$0.00135 *2/1/18*	$0.00266 *2/1/18*	$0.00001 *2/1/18*	$0.00236 *1/1/18*	$0.00083 *2/1/18*	$0.00000 *2/1/18*	$0.00072 *2/1/18*	$0.00785 *2/1/18*
G-5 Commercial Space Heating (closed) *Last Change*	23	CAMB	($0.00009) *2/1/18*	$0.00141 *2/1/18*	$0.00279 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00087 *2/1/18*	$0.00000 *2/1/18*	$0.00075 *2/1/18*	$0.00811 *2/1/18*
G-6 Optional General TOU (Non-Demand) *Last Change*	24	CAMB	($0.00006) *2/1/18*	$0.00209 *2/1/18*	$0.00411 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00129 *2/1/18*	$0.00000 *2/1/18*	$0.00111 *2/1/18*	$0.01092 *2/1/18*
G-1 General *Last Change*	29	SOUTH	($0.00008) *2/1/18*	$0.00230 *2/1/18*	$0.00453 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00142 *2/1/18*	$0.00000 *2/1/18*	$0.00123 *2/1/18*	$0.01178 *2/1/18*
G-2 Medium General TOU *Last Change*	30	SOUTH	($0.00005) *2/1/18*	$0.00138 *2/1/18*	$0.00273 *2/1/18*	$0.00001 *2/1/18*	$0.00236 *1/1/18*	$0.00085 *2/1/18*	$0.00000 *2/1/18*	$0.00074 *2/1/18*	$0.00802 *2/1/18*
G-3 Large General TOU *Last Change*	31	SOUTH	($0.00004) *2/1/18*	$0.00091 *2/1/18*	$0.00180 *2/1/18*	$0.00001 *2/1/18*	$0.00236 *1/1/18*	$0.00056 *2/1/18*	$0.00000 *2/1/18*	$0.00049 *2/1/18*	$0.00609 *2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

EASTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
G-4 General Power	32	SOUTH	($0.00008)	$0.00202	$0.00399	$0.00002	$0.00236	$0.00125	$0.00000	$0.00108	$0.01064
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-5 Commercial Space Heating (Closed)	33	SOUTH	($0.00014)	$0.00245	$0.00483	$0.00003	$0.00236	$0.00151	$0.00000	$0.00131	$0.01235
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-6 All Electric School (Closed)	34	SOUTH	($0.00007)	$0.00114	$0.00225	$0.00001	$0.00236	$0.00070	$0.00000	$0.00061	$0.00700
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-7 Optional General TOU	35	SOUTH	($0.00008)	$0.00230	$0.00453	$0.00002	$0.00236	$0.00142	$0.00000	$0.00123	$0.01178
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
S-1 Street and Security Lighting	44	ALL	($0.00024)	$0.00204	$0.00402	$0.00002	$0.00236	$0.00126	$0.00000	$0.00109	$0.01055
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
S-2 Street and Security - Customer Owned	45	ALL	($0.00024)	$0.00204	$0.00402	$0.00002	$0.00236	$0.00126	$0.00000	$0.00109	$0.01055
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*

PART C - BASIC SERVICE *
All Rates are in $/kWh across all hours and usage levels

				EASTERN MASSACHUSETTS												
Sector	**Rate Class**	**Type**	**Zone**	**01-Jan-18**	**01-Feb-18**	**01-Mar-18**	**01-Apr-18**	**01-May-18**	**01-Jun-18**	**01-Jul-18**	**01-Aug-18**	**01-Sep-18**	**01-Oct-18**	**01-Nov-18**	**01-Dec-18**	*Last Change*
Residential	R-1, R-2, R-3, R-4	Fixed	ALL	$0.12881	$0.12888	$0.12888	$0.12888	$0.12888	$0.12888							*2/1/18*
		Variable	ALL	$0.14875	$0.15312	$0.12565	$0.11690	$0.11172	$0.10670							*2/1/18*
Small C&I	All classes otherwise not listed here	Fixed	ALL	$0.12685	$0.12692	$0.12692	$0.12692	$0.12692	$0.12692							*2/1/18*
		Variable	ALL	$0.15031	$0.15425	$0.12415	$0.11237	$0.10771	$0.10586							*2/1/18*
Large C&I	G-2 (CAMB),G-3,T-2 (BOST)	Fixed	NEMA	$0.14632	$0.14639	$0.14639	$0.11492	$0.11492	$0.11492							*4/1/18*
		Variable	NEMA	$0.15155	$0.15692	$0.13014	$0.12720	$0.11860	$0.09992							*4/1/18*
Large C&I	G-2 (SOUTH),G-3,T-2 (BOST)	Fixed	SEMA	$0.11933	$0.11940	$0.11940	$0.09068	$0.09068	$0.09068							*4/1/18*
		Variable	SEMA	$0.12772	$0.12891	$0.10171	$0.08782	$0.08132	$0.10196							*4/1/18*
St. Lighting	S-1, S-2	Fixed	ALL	$0.12685	$0.12692	$0.12692	$0.12692	$0.12692	$0.12692							*2/1/18*
		Variable	ALL	$0.15031	$0.15425	$0.12415	$0.11237	$0.10771	$0.10586							*2/1/18*

* Includes the Basic Service Bad Debt Cost of $0.00130 and NSTAR Green Cost of $0.00090

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS																
												Energy Efficiency Charge (EEC)			Renewable	Total
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Energy	Delivery
R-1	7	A1/A5	ALL	Customer	$7.00		$7.00								$7.00
Residential		01/48		Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.01475	$0.01725	$0.00050	$0.10917
		32/66/68	CAPE	Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.01859	$0.02109	$0.00050	$0.11301
Last change		57/58/39			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
R-2	8	A2	ALL	Customer	$7.00		$7.00								$7.00
Residential		05		Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.00113	$0.00363	$0.00050	$0.09555
Assistance		30/37/38	CAPE	Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.00148	$0.00398	$0.00050	$0.09590
				Discount	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
R-3	9	A4/A8	ALL	Customer	$7.00		$7.00								$7.00
Residential		04/10		Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.01475	$0.01725	$0.00050	$0.09888
Space Heating		86	CAPE	Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.01859	$0.02109	$0.00050	$0.10272
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
R-4	10	A3	ALL	Customer	$7.00		$7.00								$7.00
Residential Space		07		Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.00113	$0.00363	$0.00050	$0.08526
Heating Assistance		42	CAPE	Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.00148	$0.00398	$0.00050	$0.08561
				Discount	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
									Non-Demand						
G-1	11	A9	BOST	Customer	$8.00		$8.00								$8.00
General Service				Energy (kWh) - Winter	$0.04340	$0.01907	$0.06247	$0.00000	($0.00061)	$0.02586	$0.00250	$0.00846	$0.01096	$0.00050	$0.09918
				Energy (kWh) - Summer	$0.06990	$0.01907	$0.08897	$0.00000	($0.00061)	$0.02586	$0.00250	$0.00846	$0.01096	$0.00050	$0.12568
Last change					*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
									Demand						
		B1	BOST	Customer	$11.00		$11.00								$11.00
				Demand (>10 kW) - Winter	$0.27		$0.27			$18.19					$18.46
				1st 2000 kWh	$0.04066	$0.01907	$0.05973	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00846	$0.01096	$0.00050	$0.08989
				Next 150 hrs*kW	$0.03536	$0.01907	$0.05443	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00846	$0.01096	$0.00050	$0.08459
				remainder kWh	$0.02347	$0.01907	$0.04254	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.05339
				Demand (>10 kW) - Summer	$0.83		$0.83			$56.49					$57.32
				1st 2000 kWh	$0.06536	$0.01907	$0.08443	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00846	$0.01096	$0.00050	$0.11459
				Next 150 hrs*kW	$0.03967	$0.01907	$0.05874	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00846	$0.01096	$0.00050	$0.08890
				remainder kWh	$0.02467	$0.01907	$0.04374	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.05459
Last change					*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS															
											Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
G-2	12	B2	BOST	Customer	$18.00		$18.00								$18.00
General Service				Demand (>10 kW) - Winter	$9.32		$9.32			$8.73					$18.05
				1st 2000 kWh	$0.01764	$0.01265	$0.03029	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.04114
				Next 150 hrs*kW	$0.01264	$0.01265	$0.02529	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.03614
				remainder kWh	$0.01079	$0.01265	$0.02344	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.03429
				Demand (>10 kW) - Summer	$19.99		$19.99			$23.43					$43.42
				1st 2000 kWh	$0.02746	$0.01265	$0.04011	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.05096
				Next 150 hrs*kW	$0.01435	$0.01265	$0.02700	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.03785
				remainder kWh	$0.01128	$0.01265	$0.02393	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.03478
				Transformer Credit / kW	($0.12)		($0.12)								($0.12)
Last change					*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-3	13	B3 (NEMA)	BOST	Customer	$250.00		$250.00								$250.00
General Service		G6 (SEMA)		Demand (kW) - Winter	$8.58		$8.58			$10.28					$18.86
				Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01926
				Off Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01926
				Demand (kW) - Summer	$14.54		$14.54			$10.28					$24.82
				Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01926
				Off Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01926
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
T-1	14	B5	BOST	Customer	$10.00		$10.00								$10.00
Optional				Peak kWh - Winter	$0.06920	$0.01907	$0.08827	$0.00000	($0.00061)	$0.07833	$0.00250	$0.00846	$0.01096	$0.00050	$0.17745
General Service				Off Peak kWh - Winter	$0.01764	$0.01907	$0.03671	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.04756
TOU				Peak kWh - Summer	$0.14761	$0.01907	$0.16668	$0.00000	($0.00061)	$0.17133	$0.00250	$0.00846	$0.01096	$0.00050	$0.34886
(closed)				Off Peak kWh - Summer	$0.01946	$0.01907	$0.03853	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.04938
Last change					*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
T-2	15	B7 (NEMA)	BOST	Customer (kW<=150)	$27.00		$27.00								$27.00
General Service		G8 (SEMA)		Customer (150<kW<=300)	$110.00		$110.00								$110.00
TOU				Customer (300<kW<=1000)	$160.00		$160.00								$160.00
				Customer (kW>1000)	$360.00		$360.00								$360.00
				Demand (kW) - Winter	$11.08		$11.08			$9.00					$20.08
				Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02350
				Off Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02350
				Demand (kW) - Summer	$19.45		$19.45			$9.00					$28.45
				Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02350
				Off Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02350
				Transformer Credit / kW	($0.12)		($0.12)								
Last change					*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
WR	16	E1	BOST	Customer	$150.48		$150.48								$150.48
MWRA				Demand (kW)	$0.00		$0.00			$6.93					$6.93
				Energy (kWh)	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01926
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS																
												Energy Efficiency Charge (EEC)			Renewable	Total
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Energy	Delivery
SB-G3	17	C6 (NEMA)	BOST	Customer	$250.00		$250.00								$250.00
General Service		F6 (SEMA)		Standby Demand<1MW (Winter)	$4.45		$4.45								$4.45
Standby				Standby Demand=>1 MW (Winter)	$6.24		$6.24								$6.24
				Standby Demand<1MW (Summer)	$7.37		$7.37								$7.37
				Standby Demand=>1MW (Summer)	$10.34		$10.34								$10.34
				Supplemental Service	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-0 General	18	06	CAMB	Customer	$5.00		$5.00								$5.00
(Non-Demand)				Energy (kWh)	$0.03300	$0.01092	$0.04392	$0.00000	($0.00061)	$0.02711	$0.00250	$0.00846	$0.01096	$0.00050	$0.08188
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-1 General	19	02	CAMB	Customer	$8.00		$8.00								$8.00
				Demand (<=10 kW)	$3.74		$3.74			$8.67					$12.41
				Demand (> 10 kW)	$6.99		$6.99			$8.67					$15.66
				Energy (kWh)	$0.01127	$0.01092	$0.02219	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.03304
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-2	20	62	CAMB	Customer	$97.00		$97.00								$97.00
Large General				Demand (<=100 kVA)	$4.04		$4.04			$5.46					$9.50
Secondary				Demand (> 100 kVA)	$5.01		$5.01			$11.16					$16.17
Service				Peak kWh	$0.00949	$0.00840	$0.01789	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02874
				Low A kWh	$0.00949	$0.00840	$0.01789	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02874
				Low B kWh	$0.00949	$0.00840	$0.01789	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02874
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-3	21	70	CAMB	Customer	$97.00		$97.00								$97.00
Large General				Demand (<=100 kVA)	$0.00		$0.00			$477.65					$477.65
TOU				Demand (> 100 kVA)	$4.31		$4.31			$8.48					$12.79
13.8 kV Service				Peak kWh	$0.00329	$0.00560	$0.00889	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01974
				Low A kWh	$0.00329	$0.00560	$0.00889	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01974
				Low B kWh	$0.00329	$0.00560	$0.00889	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01974
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-4	22	52	CAMB	Customer	$12.00		$12.00								$12.00
Optional General				Demand (kW)	$4.14		$4.14			$9.98					$14.12
TOU				Peak kWh	$0.01038	$0.00785	$0.01823	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02908
				Low A kWh	$0.01038	$0.00785	$0.01823	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02908
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-5	23	36	CAMB	Customer	$8.00		$8.00								$8.00
Commercial				Energy (<=5000 kWh)	$0.01770	$0.00811	$0.02581	$0.00000	($0.00061)	$0.02390	$0.00250	$0.00846	$0.01096	$0.00050	$0.06056
Space Heating				Energy (>5000 kWh)	$0.02326	$0.00811	$0.03137	$0.00000	($0.00061)	$0.03408	$0.00250	$0.00846	$0.01096	$0.00050	$0.07630
(closed)															
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS															
												Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
G-6	24	51	CAMB	Customer	$8.22		$8.22								$8.22
Optional General				Peak kWh	$0.06346	$0.01092	$0.07438	$0.00000	($0.00061)	$0.02711	$0.00250	$0.00846	$0.01096	$0.00050	$0.11234
TOU				Low A kWh	$0.02338	$0.01092	$0.03430	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.04515
(Non-Demand)															
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
SB-1	25	D1	CAMB	Customer	$781.00		$781.00								$781.00
Standby				Standby Demand/Replacement	$4.37		$4.37			$7.99					$12.36
				Minimum Reservation	$0.00		$0.00			$0.61					$0.61
				Replacement Energy	$0.00000	$0.00560	$0.00560	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01645
MS-1	26	D4	CAMB	Customer	$781.00		$781.00								$781.00
Maintenance				Standby Demand/Replacement	$4.37		$4.37								$4.37
				Replacement Energy	$0.00000	$0.00560	$0.00560	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01645
SS-1				Customer	$0.00										
Supplemental	27	D7		All Rate Components	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
SB-G3	28	46	CAMB	Customer	$97.00		$97.00								$97.00
General Service				Standby Demand<=1MW											
Standby				<=100 kVA	$0.00		$0.00								$0.00
				>100 kVA	$0.78		$0.78								$0.78
				Standby Demand=>1 MW											
				<=100 kVA	$0.00		$0.00								$0.00
				>100 kVA	$1.78		$1.78								$1.78
				Supplemental Demand											
				<=100 kVA	$0.00		$0.00			$477.65					$477.65
				>100 kVA	$6.36		$6.36			$8.48					$14.84
				Supplemental Energy	$0.00000	$0.00560	$0.00560	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01645
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
				Annual/Seasonal Optional											
G-1 General	29	33/23	SOUTH	Customer	$6.00		$6.00								$6.00
				Demand (<=10 kW)	$0.00		$0.00								$0.00
				Demand (>10 kW)	$4.85		$4.85								$4.85
				Energy (< =2300 kWh)	$0.04067	$0.01178	$0.05245	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00846	$0.01096	$0.00050	$0.08966
				Energy (>2300 kWh)	$0.01102	$0.01178	$0.02280	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00846	$0.01096	$0.00050	$0.06001
			CAPE	Energy (< =2300 kWh)	$0.04067	$0.01178	$0.05245	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.08650
			CAPE	Energy (>2300 kWh)	$0.01102	$0.01178	$0.02280	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.05685
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
				Seasonal											
		35	SOUTH	Cust	$6.00		$6.00								$6.00
				Demand (<=10 kW)	$0.00		$0.00								$0.00
				Demand (>10 kW)	$4.25		$4.25								$4.25
				Energy (< =1800 kWh)	$0.07506	$0.01178	$0.08684	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00846	$0.01096	$0.00050	$0.12405
				Energy (>1800 kWh)	$0.02385	$0.01178	$0.03563	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00846	$0.01096	$0.00050	$0.07284
			CAPE	Energy (< =1800 kWh)	$0.07506	$0.01178	$0.08684	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.12089
			CAPE	Energy (>1800 kWh)	$0.02385	$0.01178	$0.03563	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.06968
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS																
												Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
G-2	30	84	SOUTH	Cust	$370.00		$370.00								$370.00
Medium General				Demand (kVA)	$1.51		$1.51			$8.16					$9.67
TOU				Peak kWh	$0.01769	$0.00802	$0.02571	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00846	$0.01096	$0.00050	$0.03933
				Low A kWh	$0.01488	$0.00802	$0.02290	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00846	$0.01096	$0.00050	$0.03652
				Low B kWh	$0.00965	$0.00802	$0.01767	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00846	$0.01096	$0.00050	$0.03129
			CAPE	Peak kWh	$0.01769	$0.00802	$0.02571	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00530	$0.00780	$0.00050	$0.03617
			CAPE	Low A kWh	$0.01488	$0.00802	$0.02290	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00530	$0.00780	$0.00050	$0.03336
			CAPE	Low B kWh	$0.00965	$0.00802	$0.01767	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00530	$0.00780	$0.00050	$0.02813
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-3	31	24	SOUTH	Customer	$930.00		$930.00								$930.00
Large General				Demand (kVA)	$0.87		$0.87			$8.22					$9.09
TOU				Energy (kWh) - Peak	$0.01242	$0.00609	$0.01851	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02936
				Energy (kWh) - Low A	$0.01142	$0.00609	$0.01751	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02836
				Energy (kWh) - Low B	$0.00791	$0.00609	$0.01400	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02485
			CAPE	Energy (kWh) - Peak	$0.01242	$0.00609	$0.01851	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.02620
			CAPE	Energy (kWh) - Low A	$0.01142	$0.00609	$0.01751	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.02520
			CAPE	Energy (kWh) - Low B	$0.00791	$0.00609	$0.01400	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.02169
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-4	32	41	SOUTH	Customer	$6.00		$6.00								$6.00
General Power				Demand (kW)	$1.74		$1.74			$2.69					$4.43
				Energy (kWh)	$0.01998	$0.01064	$0.03062	$0.00000	($0.00061)	$0.00326	$0.00250	$0.00846	$0.01096	$0.00050	$0.04473
			CAPE	Energy (kWh)	$0.01998	$0.01064	$0.03062	$0.00000	($0.00061)	$0.00326	$0.00250	$0.00530	$0.00780	$0.00050	$0.04157
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-5	33	88	SOUTH	Customer	$6.00		$6.00								$6.00
Commercial				Energy (kWh)	$0.03563	$0.01235	$0.04798	$0.00000	($0.00061)	$0.03267	$0.00250	$0.00846	$0.01096	$0.00050	$0.09150
Space Heating			CAPE	Energy (kWh)	$0.03563	$0.01235	$0.04798	$0.00000	($0.00061)	$0.03267	$0.00250	$0.00530	$0.00780	$0.00050	$0.08834
(Closed)															
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-6	34	22	SOUTH	Customer	$30.00		$30.00								$30.00
All Electric School				Energy (kWh)	$0.01633	$0.00700	$0.02333	$0.00000	($0.00061)	$0.02666	$0.00250	$0.00846	$0.01096	$0.00050	$0.06084
(Closed)			CAPE	Energy (kWh)	$0.01633	$0.00700	$0.02333	$0.00000	($0.00061)	$0.02666	$0.00250	$0.00530	$0.00780	$0.00050	$0.05768
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
				Annual											
G-7	35	55	SOUTH	Customer	$10.00		$10.00								$10.00
Optional General				Demand (kW)	$3.33		$3.33			$10.63					$13.96
TOU				Peak kWh	$0.02290	$0.01178	$0.03468	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.04553
				Low A kWh	$0.01604	$0.01178	$0.02782	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.03867
			CAPE	Peak kWh	$0.02290	$0.01178	$0.03468	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.04237
			CAPE	Low A kWh	$0.01604	$0.01178	$0.02782	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.03551
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
				Seasonal											
		31	SOUTH	Customer	$10.00		$10.00								$10.00
				Demand (kW)	$3.36		$3.36			$4.96					$8.32
				Peak kWh	$0.04453	$0.01178	$0.05631	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.06716
				Low A kWh	$0.03745	$0.01178	$0.04923	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.06008
			CAPE	Peak kWh	$0.04453	$0.01178	$0.05631	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.06400
			CAPE	Low A kWh	$0.03745	$0.01178	$0.04923	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.05692
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS															
											Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
S-1	44	C1/C3	ALL	Fixture Charge	Per Rate Schedule		Per Rate Schedule								Per Rate Schedule
Street and		19/80		Energy (kWh)		$0.01055		$0.00000	($0.00061)	$0.01258	$0.00250	$0.00846	$0.01096	$0.00050	
Security Lighting		79/81	CAPE	Energy (kWh)		$0.01055		$0.00000	($0.00061)	$0.01258	$0.00250	$0.00530	$0.00780	$0.00050	
Last Change					*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
S-2	45	C2/C4	ALL	Customer	$6.58		$6.58								$6.58
Street and Security -		83/89		Energy (kWh)	$0.02536	$0.01055	$0.03591	$0.00000	($0.00061)	$0.01258	$0.00250	$0.00846	$0.01096	$0.00050	$0.05934
Customer Owned		82/96	CAPE	Energy (kWh)	$0.02536	$0.01055	$0.03591	$0.00000	($0.00061)	$0.01258	$0.00250	$0.00530	$0.00780	$0.00050	$0.05618
Last Change					*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*

(2) Transmission Charge for Rate R-2 customers in the Boston service area is $0.03057 from February 1, 2018 through December 31, 2018

Summer Months - June thru September
Winter Months - October thru May

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

EASTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
R-1 Residential *Last change*	7	ALL	($0.00011) *2/1/18*	$0.00375 *2/1/18*	$0.00738 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00231 *2/1/18*	$0.00000 *2/1/18*	$0.00200 *2/1/18*	$0.01773 *2/1/18*
R-2 Residential Assistance *Last change*	8	ALL	($0.00011) *2/1/18*	$0.00375 *2/1/18*	$0.00738 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00231 *2/1/18*	$0.00000 *2/1/18*	$0.00200 *2/1/18*	$0.01773 *2/1/18*
R-3 Residential Space Heating *Last change*	9	ALL	($0.00010) *2/1/18*	$0.00295 *2/1/18*	$0.00580 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00182 *2/1/18*	$0.00000 *2/1/18*	$0.00157 *2/1/18*	$0.01443 *2/1/18*
R-4 Residential Space Heating Assistance *Last change*	10	ALL	($0.00010) *2/1/18*	$0.00295 *2/1/18*	$0.00580 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00182 *2/1/18*	$0.00000 *2/1/18*	$0.00157 *2/1/18*	$0.01443 *2/1/18*
G-1 General Service *Last change*	11	BOST	($0.00011) *2/1/18*	$0.00407 *2/1/18*	$0.00803 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00251 *2/1/18*	$0.00000 *2/1/18*	$0.00217 *2/1/18*	$0.01907 *2/1/18*
G-2 General Service *Last change*	12	BOST	($0.00005) *2/1/18*	$0.00250 *2/1/18*	$0.00493 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00154 *2/1/18*	$0.00000 *2/1/18*	$0.00134 *2/1/18*	$0.01265 *2/1/18*
G-3 General Service *Last change*	13	BOST	($0.00003) *2/1/18*	$0.00147 *2/1/18*	$0.00290 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00091 *2/1/18*	$0.00000 *2/1/18*	$0.00078 *2/1/18*	$0.00841 *2/1/18*
T-1 General Service Optional Time-of-Use *Last change*	14	BOST	($0.00011) *2/1/18*	$0.00407 *2/1/18*	$0.00803 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00251 *2/1/18*	$0.00000 *2/1/18*	$0.00217 *2/1/18*	$0.01907 *2/1/18*
T-2 General Service Time-of-Use *Last change*	15	BOST	($0.00005) *2/1/18*	$0.00250 *2/1/18*	$0.00493 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00154 *2/1/18*	$0.00000 *2/1/18*	$0.00134 *2/1/18*	$0.01265 *2/1/18*
WR MWRA *Last Change*	16	BOST	($0.00003) *2/1/18*	$0.00147 *2/1/18*	$0.00290 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00091 *2/1/18*	$0.00000 *2/1/18*	$0.00078 *2/1/18*	$0.00841 *2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

EASTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
G-0 General (Non-Demand)	18	CAMB	($0.00006)	$0.00209	$0.00411	$0.00002	$0.00236	$0.00129	$0.00000	$0.00111	$0.01092
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-1 General	19	CAMB	($0.00006)	$0.00209	$0.00411	$0.00002	$0.00236	$0.00129	$0.00000	$0.00111	$0.01092
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-2 Large General TOU Secondary Service	20	CAMB	($0.00005)	$0.00147	$0.00290	$0.00002	$0.00236	$0.00091	$0.00000	$0.00079	$0.00840
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-3 Large General TOU 13.8 kV Service	21	CAMB	($0.00003)	$0.00079	$0.00156	$0.00001	$0.00236	$0.00049	$0.00000	$0.00042	$0.00560
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-4 Optional General TOU	22	CAMB	($0.00008)	$0.00135	$0.00266	$0.00001	$0.00236	$0.00083	$0.00000	$0.00072	$0.00785
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-5 Commercial Space Heating (closed)	23	CAMB	($0.00009)	$0.00141	$0.00279	$0.00002	$0.00236	$0.00087	$0.00000	$0.00075	$0.00811
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-6 Optional General TOU (Non-Demand)	24	CAMB	($0.00006)	$0.00209	$0.00411	$0.00002	$0.00236	$0.00129	$0.00000	$0.00111	$0.01092
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-1 General	29	SOUTH	($0.00008)	$0.00230	$0.00453	$0.00002	$0.00236	$0.00142	$0.00000	$0.00123	$0.01178
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-2 Medium General TOU	30	SOUTH	($0.00005)	$0.00138	$0.00273	$0.00001	$0.00236	$0.00085	$0.00000	$0.00074	$0.00802
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
G-3 Large General TOU	31	SOUTH	($0.00004)	$0.00091	$0.00180	$0.00001	$0.00236	$0.00056	$0.00000	$0.00049	$0.00609
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

EASTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
G-4 General Power *Last Change*	32	SOUTH	($0.00008) *2/1/18*	$0.00202 *2/1/18*	$0.00399 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00125 *2/1/18*	$0.00000 *2/1/18*	$0.00108 *2/1/18*	$0.01064 *2/1/18*
G-5 Commercial Space Heating (Closed) *Last Change*	33	SOUTH	($0.00014) *2/1/18*	$0.00245 *2/1/18*	$0.00483 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00151 *2/1/18*	$0.00000 *2/1/18*	$0.00131 *2/1/18*	$0.01235 *2/1/18*
G-6 All Electric School (Closed) *Last Change*	34	SOUTH	($0.00007) *2/1/18*	$0.00114 *2/1/18*	$0.00225 *2/1/18*	$0.00001 *2/1/18*	$0.00236 *1/1/18*	$0.00070 *2/1/18*	$0.00000 *2/1/18*	$0.00061 *2/1/18*	$0.00700 *2/1/18*
G-7 Optional General TOU *Last Change*	35	SOUTH	($0.00008) *2/1/18*	$0.00230 *2/1/18*	$0.00453 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00142 *2/1/18*	$0.00000 *2/1/18*	$0.00123 *2/1/18*	$0.01178 *2/1/18*
S-1 Street and Security Lighting *Last Change*	44	ALL	($0.00024) *2/1/18*	$0.00204 *2/1/18*	$0.00402 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00126 *2/1/18*	$0.00000 *2/1/18*	$0.00109 *2/1/18*	$0.01055 *2/1/18*
S-2 Street and Security - Customer Owned *Last Change*	45	ALL	($0.00024) *2/1/18*	$0.00204 *2/1/18*	$0.00402 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00126 *2/1/18*	$0.00000 *2/1/18*	$0.00109 *2/1/18*	$0.01055 *2/1/18*

PART C - BASIC SERVICE *
All Rates are in $/kWh across all hours and usage levels

EASTERN MASSACHUSETTS															
Sector	**Rate Class**	**Type**	**Zone**	**01-Jan-18**	**01-Feb-18**	**01-Mar-18**	**01-Apr-18**	**01-May-18**	**01-Jun-18**	**01-Jul-18**	**01-Aug-18**	**01-Sep-18**	**01-Oct-18**	**01-Nov-18**	**01-Dec-18**	*Last Change*
Residential	R-1, R-2, R-3, R-4	Fixed	ALL	$0.12881	$0.12888	$0.12888	$0.12888	$0.12888	$0.12888	$0.11397	$0.11397	$0.11397	$0.11397	$0.11397	$0.11397	*7/1/18*
		Variable	ALL	$0.14875	$0.15312	$0.12565	$0.11690	$0.11172	$0.10670	$0.10350	$0.10383	$0.11091	$0.12008	$0.11931	$0.13302	*7/1/18*
Small C&I	All classes otherwise not listed here	Fixed	ALL	$0.12685	$0.12692	$0.12692	$0.12692	$0.12692	$0.12692	$0.11403	$0.11403	$0.11403	$0.11403	$0.11403	$0.11403	*7/1/18*
		Variable	ALL	$0.15031	$0.15425	$0.12415	$0.11237	$0.10771	$0.10586	$0.10708	$0.10617	$0.10900	$0.11430	$0.11683	$0.13414	*7/1/18*
Large C&I	G-2 (CAMB),G-3,T-2 (BOST)	Fixed	NEMA	$0.14632	$0.14639	$0.14639	$0.11492	$0.11492	$0.11492	$0.11498	$0.11498	$0.11498				*7/1/18*
		Variable	NEMA	$0.15155	$0.15692	$0.13014	$0.12720	$0.11860	$0.09992	$0.11476	$0.11248	$0.11812				*7/1/18*
Large C&I	G-2 (SOUTH),G-3,T-2 (BOST)	Fixed	SEMA	$0.11933	$0.11940	$0.11940	$0.09068	$0.09068	$0.09068	$0.10398	$0.10398	$0.10398				*7/1/18*
		Variable	SEMA	$0.12772	$0.12891	$0.10171	$0.08782	$0.08132	$0.10196	$0.10405	$0.10277	$0.10522				*7/1/18*
St. Lighting	S-1, S-2	Fixed	ALL	$0.12685	$0.12692	$0.12692	$0.12692	$0.12692	$0.12692	$0.11403	$0.11403	$0.11403	$0.11403	$0.11403	$0.11403	*7/1/18*
		Variable	ALL	$0.15031	$0.15425	$0.12415	$0.11237	$0.10771	$0.10586	$0.10708	$0.10617	$0.10900	$0.11430	$0.11683	$0.13414	*7/1/18*

* Includes the Basic Service Bad Debt Cost of $0.00130 and NSTAR Green Cost of $0.00090

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS															
											Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
R-1	7	A1/A5	ALL	Customer	$7.00		$7.00								$7.00
Residential		01/48		Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.01475	$0.01725	$0.00050	$0.10917
		32/66/68	CAPE	Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.01859	$0.02109	$0.00050	$0.11301
Last change		57/58/39			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
R-2	8	A2	ALL	Customer	$7.00		$7.00								$7.00
Residential		05		Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.00113	$0.00363	$0.00050	$0.09555
Assistance		30/37/38	CAPE	Energy (kWh)	$0.04372	$0.01773	$0.06145	$0.00000	($0.00061)	$0.03058	$0.00250	$0.00148	$0.00398	$0.00050	$0.09590
				Discount	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
R-3	9	A4/A8	ALL	Customer	$7.00		$7.00								$7.00
Residential		04/10		Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.01475	$0.01725	$0.00050	$0.09888
Space Heating		86	CAPE	Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.01859	$0.02109	$0.00050	$0.10272
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
R-4	10	A3	ALL	Customer	$7.00		$7.00								$7.00
Residential Space		07		Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.00113	$0.00363	$0.00050	$0.08526
Heating Assistance		42	CAPE	Energy (kWh)	$0.03835	$0.01443	$0.05278	$0.00000	($0.00061)	$0.02896	$0.00250	$0.00148	$0.00398	$0.00050	$0.08561
				Discount	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
									Non-Demand						
G-1	11	A9	BOST	Customer	$8.00		$8.00								$8.00
General Service				Energy (kWh) - Winter	$0.04340	$0.01907	$0.06247	$0.00000	($0.00061)	$0.02586	$0.00250	$0.00846	$0.01096	$0.00050	$0.09918
				Energy (kWh) - Summer	$0.06990	$0.01907	$0.08897	$0.00000	($0.00061)	$0.02586	$0.00250	$0.00846	$0.01096	$0.00050	$0.12568
Last change					*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
									Demand						
		B1	BOST	Customer	$11.00		$11.00								$11.00
				Demand (>10 kW) - Winter	$0.27		$0.27			$18.19					$18.46
				1st 2000 kWh	$0.04066	$0.01907	$0.05973	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00846	$0.01096	$0.00050	$0.08989
				Next 150 hrs*kW	$0.03536	$0.01907	$0.05443	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00846	$0.01096	$0.00050	$0.08459
				remainder kWh	$0.02347	$0.01907	$0.04254	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.05339
				Demand (>10 kW) - Summer	$0.83		$0.83			$56.49					$57.32
				1st 2000 kWh	$0.06536	$0.01907	$0.08443	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00846	$0.01096	$0.00050	$0.11459
				Next 150 hrs*kW	$0.03967	$0.01907	$0.05874	$0.00000	($0.00061)	$0.01931	$0.00250	$0.00846	$0.01096	$0.00050	$0.08890
				remainder kWh	$0.02467	$0.01907	$0.04374	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.05459
Last change					*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS

Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	Energy Efficiency Charge (EEC) System Benefits	EEC Recon. Factor	EEC Total EEC	Renewable Energy	Total Delivery
G-2	12	B2	BOST	Customer	$18.00		$18.00								$18.00
General Service				Demand (>10 kW) - Winter	$9.32		$9.32			$8.73					$18.05
				1st 2000 kWh	$0.01764	$0.01265	$0.03029	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.04114
				Next 150 hrs*kW	$0.01264	$0.01265	$0.02529	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.03614
				remainder kWh	$0.01079	$0.01265	$0.02344	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.03429
				Demand (>10 kW) - Summer	$19.99		$19.99			$23.43					$43.42
				1st 2000 kWh	$0.02746	$0.01265	$0.04011	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.05096
				Next 150 hrs*kW	$0.01435	$0.01265	$0.02700	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.03785
				remainder kWh	$0.01128	$0.01265	$0.02393	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.03478
				Transformer Credit / kW	($0.12)		($0.12)								($0.12)
Last change					*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-3	13	B3 (NEMA)	BOST	Customer	$250.00		$250.00								$250.00
General Service		G6 (SEMA)		Demand (kW) - Winter	$8.58		$8.58			$10.28					$18.86
				Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01926
				Off Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01926
				Demand (kW) - Summer	$14.54		$14.54			$10.28					$24.82
				Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01926
				Off Peak kWh	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01926
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
T-1	14	B5	BOST	Customer	$10.00		$10.00								$10.00
Optional				Peak kWh - Winter	$0.06920	$0.01907	$0.08827	$0.00000	($0.00061)	$0.07833	$0.00250	$0.00846	$0.01096	$0.00050	$0.17745
General Service				Off Peak kWh - Winter	$0.01764	$0.01907	$0.03671	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.04756
TOU				Peak kWh - Summer	$0.14761	$0.01907	$0.16668	$0.00000	($0.00061)	$0.17133	$0.00250	$0.00846	$0.01096	$0.00050	$0.34886
(closed)				Off Peak kWh - Summer	$0.01946	$0.01907	$0.03853	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.04938
Last change					*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
T-2	15	B7 (NEMA)	BOST	Customer (kW<=150)	$27.00		$27.00								$27.00
General Service		G8 (SEMA)		Customer (150<kW<=300)	$110.00		$110.00								$110.00
TOU				Customer (300<kW<=1000)	$160.00		$160.00								$160.00
				Customer (kW>1000)	$360.00		$360.00								$360.00
				Demand (kW) - Winter	$11.08		$11.08			$9.00					$20.08
				Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02350
				Off Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02350
				Demand (kW) - Summer	$19.45		$19.45			$9.00					$28.45
				Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02350
				Off Peak kWh	$0.00000	$0.01265	$0.01265	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02350
				Transformer Credit / kW	($0.12)		($0.12)								
Last change					*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
WR	16	E1	BOST	Customer	$150.48		$150.48								$150.48
MWRA				Demand (kW)	$0.00		$0.00			$6.93					$6.93
				Energy (kWh)	$0.00000	$0.00841	$0.00841	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01926
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS															
	MDPU	Rate	Service	Rate	Base	Reconciling	Total	Revenue			Energy Efficiency Charge (EEC)			Renewable	Total
Schedule	No.	Code	Area	Component	Distribution	Rate Adjust (1)	Distribution	Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Energy	Delivery
SB-G3	17	C6 (NEMA)	BOST	Customer	$250.00		$250.00								$250.00
General Service		F6 (SEMA)		Standby Demand<1MW (Winter)	$4.45		$4.45								$4.45
Standby				Standby Demand=>1 MW (Winter)	$6.24		$6.24								$6.24
				Standby Demand<1MW (Summer)	$7.37		$7.37								$7.37
				Standby Demand=>1MW (Summer)	$10.34		$10.34								$10.34
				Supplemental Service	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-0 General	18	06	CAMB	Customer	$5.00		$5.00								$5.00
(Non-Demand)				Energy (kWh)	$0.03300	$0.01092	$0.04392	$0.00000	($0.00061)	$0.02711	$0.00250	$0.00846	$0.01096	$0.00050	$0.08188
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-1 General	19	02	CAMB	Customer	$8.00		$8.00								$8.00
				Demand (<=10 kW)	$3.74		$3.74			$8.67					$12.41
				Demand (> 10 kW)	$6.99		$6.99			$8.67					$15.66
				Energy (kWh)	$0.01127	$0.01092	$0.02219	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.03304
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-2	20	62	CAMB	Customer	$97.00		$97.00								$97.00
Large General				Demand (<=100 kVA)	$4.04		$4.04			$5.46					$9.50
Secondary				Demand (> 100 kVA)	$5.01		$5.01			$11.16					$16.17
Service				Peak kWh	$0.00949	$0.00840	$0.01789	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02874
				Low A kWh	$0.00949	$0.00840	$0.01789	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02874
				Low B kWh	$0.00949	$0.00840	$0.01789	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02874
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-3	21	70	CAMB	Customer	$97.00		$97.00								$97.00
Large General				Demand (<=100 kVA)	$0.00		$0.00			$477.65					$477.65
TOU				Demand (> 100 kVA)	$4.31		$4.31			$8.48					$12.79
13.8 kV Service				Peak kWh	$0.00329	$0.00560	$0.00889	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01974
				Low A kWh	$0.00329	$0.00560	$0.00889	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01974
				Low B kWh	$0.00329	$0.00560	$0.00889	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01974
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-4	22	52	CAMB	Customer	$12.00		$12.00								$12.00
Optional General				Demand (kW)	$4.14		$4.14			$9.98					$14.12
TOU				Peak kWh	$0.01038	$0.00785	$0.01823	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02908
				Low A kWh	$0.01038	$0.00785	$0.01823	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02908
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-5	23	36	CAMB	Customer	$8.00		$8.00								$8.00
Commercial				Energy (<=5000 kWh)	$0.01770	$0.00811	$0.02581	$0.00000	($0.00061)	$0.02390	$0.00250	$0.00846	$0.01096	$0.00050	$0.06056
Space Heating				Energy (>5000 kWh)	$0.02326	$0.00811	$0.03137	$0.00000	($0.00061)	$0.03408	$0.00250	$0.00846	$0.01096	$0.00050	$0.07630
(closed)															
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS															
											Energy Efficiency Charge (EEC)			Renewable	Total
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Energy	Delivery
G-6	24	51	CAMB	Customer	$8.22		$8.22								$8.22
Optional General				Peak kWh	$0.06346	$0.01092	$0.07438	$0.00000	($0.00061)	$0.02711	$0.00250	$0.00846	$0.01096	$0.00050	$0.11234
TOU				Low A kWh	$0.02338	$0.01092	$0.03430	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.04515
(Non-Demand)															
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
SB-1	25	D1	CAMB	Customer	$781.00		$781.00								$781.00
Standby				Standby Demand/Replacement	$4.37		$4.37			$7.99					$12.36
				Minimum Reservation	$0.00		$0.00			$0.61					$0.61
				Replacement Energy	$0.00000	$0.00560	$0.00560	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01645
MS-1	26	D4	CAMB	Customer	$781.00		$781.00								$781.00
Maintenance				Standby Demand/Replacement	$4.37		$4.37								$4.37
				Replacement Energy	$0.00000	$0.00560	$0.00560	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01645
SS-1				Customer	$0.00										
Supplemental	27	D7		All Rate Components	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3	per G-3
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
SB-G3	28	46	CAMB	Customer	$97.00		$97.00								$97.00
General Service				Standby Demand<=1MW											
Standby				<=100 kVA	$0.00		$0.00								$0.00
				>100 kVA	$0.78		$0.78								$0.78
				Standby Demand=>1 MW											
				<=100 kVA	$0.00		$0.00								$0.00
				>100 kVA	$1.78		$1.78								$1.78
				Supplemental Demand											
				<=100 kVA	$0.00		$0.00			$477.65					$477.65
				>100 kVA	$6.36		$6.36			$8.48					$14.84
				Supplemental Energy	$0.00000	$0.00560	$0.00560	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.01645
Last change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
				Annual/Seasonal Optional											
G-1 General	29	33/23	SOUTH	Customer	$6.00		$6.00								$6.00
				Demand (<=10 kW)	$0.00		$0.00								$0.00
				Demand (>10 kW)	$4.85		$4.85								$4.85
				Energy (< =2300 kWh)	$0.04067	$0.01178	$0.05245	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00846	$0.01096	$0.00050	$0.08966
				Energy (>2300 kWh)	$0.01102	$0.01178	$0.02280	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00846	$0.01096	$0.00050	$0.06001
			CAPE	Energy (< =2300 kWh)	$0.04067	$0.01178	$0.05245	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.08650
			CAPE	Energy (>2300 kWh)	$0.01102	$0.01178	$0.02280	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.05685
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
				Seasonal											
		35	SOUTH	Cust	$6.00		$6.00								$6.00
				Demand (<=10 kW)	$0.00		$0.00								$0.00
				Demand (>10 kW)	$4.25		$4.25								$4.25
				Energy (< =1800 kWh)	$0.07506	$0.01178	$0.08684	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00846	$0.01096	$0.00050	$0.12405
				Energy (>1800 kWh)	$0.02385	$0.01178	$0.03563	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00846	$0.01096	$0.00050	$0.07284
			CAPE	Energy (< =1800 kWh)	$0.07506	$0.01178	$0.08684	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.12089
			CAPE	Energy (>1800 kWh)	$0.02385	$0.01178	$0.03563	$0.00000	($0.00061)	$0.02636	$0.00250	$0.00530	$0.00780	$0.00050	$0.06968
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS															
										Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
G-2	30	84	SOUTH	Cust	$370.00		$370.00								$370.00
Medium General				Demand (kVA)	$1.51		$1.51			$8.16					$9.67
TOU				Peak kWh	$0.01769	$0.00802	$0.02571	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00846	$0.01096	$0.00050	$0.03933
				Low A kWh	$0.01488	$0.00802	$0.02290	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00846	$0.01096	$0.00050	$0.03652
				Low B kWh	$0.00965	$0.00802	$0.01767	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00846	$0.01096	$0.00050	$0.03129
			CAPE	Peak kWh	$0.01769	$0.00802	$0.02571	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00530	$0.00780	$0.00050	$0.03617
			CAPE	Low A kWh	$0.01488	$0.00802	$0.02290	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00530	$0.00780	$0.00050	$0.03336
			CAPE	Low B kWh	$0.00965	$0.00802	$0.01767	$0.00000	($0.00061)	$0.00277	$0.00250	$0.00530	$0.00780	$0.00050	$0.02813
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-3	31	24	SOUTH	Customer	$930.00		$930.00								$930.00
Large General				Demand (kVA)	$0.87		$0.87			$8.22					$9.09
TOU				Energy (kWh) - Peak	$0.01242	$0.00609	$0.01851	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02936
				Energy (kWh) - Low A	$0.01142	$0.00609	$0.01751	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02836
				Energy (kWh) - Low B	$0.00791	$0.00609	$0.01400	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.02485
			CAPE	Energy (kWh) - Peak	$0.01242	$0.00609	$0.01851	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.02620
			CAPE	Energy (kWh) - Low A	$0.01142	$0.00609	$0.01751	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.02520
			CAPE	Energy (kWh) - Low B	$0.00791	$0.00609	$0.01400	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.02169
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-4	32	41	SOUTH	Customer	$6.00		$6.00								$6.00
General Power				Demand (kW)	$1.74		$1.74			$2.69					$4.43
				Energy (kWh)	$0.01998	$0.01064	$0.03062	$0.00000	($0.00061)	$0.00326	$0.00250	$0.00846	$0.01096	$0.00050	$0.04473
			CAPE	Energy (kWh)	$0.01998	$0.01064	$0.03062	$0.00000	($0.00061)	$0.00326	$0.00250	$0.00530	$0.00780	$0.00050	$0.04157
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-5	33	88	SOUTH	Customer	$6.00		$6.00								$6.00
Commercial				Energy (kWh)	$0.03563	$0.01235	$0.04798	$0.00000	($0.00061)	$0.03267	$0.00250	$0.00846	$0.01096	$0.00050	$0.09150
Space Heating			CAPE	Energy (kWh)	$0.03563	$0.01235	$0.04798	$0.00000	($0.00061)	$0.03267	$0.00250	$0.00530	$0.00780	$0.00050	$0.08834
(Closed)															
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-6	34	22	SOUTH	Customer	$30.00		$30.00								$30.00
All Electric School				Energy (kWh)	$0.01633	$0.00700	$0.02333	$0.00000	($0.00061)	$0.02666	$0.00250	$0.00846	$0.01096	$0.00050	$0.06084
(Closed)			CAPE	Energy (kWh)	$0.01633	$0.00700	$0.02333	$0.00000	($0.00061)	$0.02666	$0.00250	$0.00530	$0.00780	$0.00050	$0.05768
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
				Annual											
G-7	35	55	SOUTH	Customer	$10.00		$10.00								$10.00
Optional General				Demand (kW)	$3.33		$3.33			$10.63					$13.96
TOU				Peak kWh	$0.02290	$0.01178	$0.03468	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.04553
				Low A kWh	$0.01604	$0.01178	$0.02782	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.03867
			CAPE	Peak kWh	$0.02290	$0.01178	$0.03468	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.04237
			CAPE	Low A kWh	$0.01604	$0.01178	$0.02782	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.03551
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
				Seasonal											
		31	SOUTH	Customer	$10.00		$10.00								$10.00
				Demand (kW)	$3.36		$3.36			$4.96					$8.32
				Peak kWh	$0.04453	$0.01178	$0.05631	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.06716
				Low A kWh	$0.03745	$0.01178	$0.04923	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00846	$0.01096	$0.00050	$0.06008
			CAPE	Peak kWh	$0.04453	$0.01178	$0.05631	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.06400
			CAPE	Low A kWh	$0.03745	$0.01178	$0.04923	$0.00000	($0.00061)	$0.00000	$0.00250	$0.00530	$0.00780	$0.00050	$0.05692
Last Change					*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

EASTERN MASSACHUSETTS															
											Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Rate Code	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission (2)	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
S-1	44	C1/C3	ALL	Fixture Charge	Per Rate Schedule		Per Rate Schedule	$0.00000	($0.00061)	$0.01258	$0.00250	$0.00846	$0.01096	$0.00050	Per Rate Schedule
Street and		19/80		Energy (kWh)		$0.01055		$0.00000	($0.00061)	$0.01258	$0.00250	$0.00530	$0.00780	$0.00050	
Security Lighting		79/81	CAPE	Energy (kWh)		$0.01055		$0.00000	($0.00061)	$0.01258	$0.00250	$0.00530	$0.00780	$0.00050	
Last Change					*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*2/1/18 -*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
S-2	45	C2/C4	ALL	Customer	$6.58		$6.58								$6.58
Street and Security -		83/89		Energy (kWh)	$0.02536	$0.01055	$0.03591	$0.00000	($0.00061)	$0.01258	$0.00250	$0.00846	$0.01096	$0.00050	$0.05934
Customer Owned		82/96	CAPE	Energy (kWh)	$0.02536	$0.01055	$0.03591	$0.00000	($0.00061)	$0.01258	$0.00250	$0.00530	$0.00780	$0.00050	$0.05618
Last Change					*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/02*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*

(2) Transmission Charge for Rate R-2 customers in the Boston service area is $0.03057 from February 1, 2018 through December 31, 2018

Summer Months - June thru September
Winter Months - October thru May

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

EASTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
R-1 Residential *Last change*	7	ALL	($0.00011) *2/1/18*	$0.00375 *2/1/18*	$0.00738 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00231 *2/1/18*	$0.00000 *2/1/18*	$0.00200 *2/1/18*	$0.01773 *2/1/18*
R-2 Residential Assistance *Last change*	8	ALL	($0.00011) *2/1/18*	$0.00375 *2/1/18*	$0.00738 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00231 *2/1/18*	$0.00000 *2/1/18*	$0.00200 *2/1/18*	$0.01773 *2/1/18*
R-3 Residential Space Heating *Last change*	9	ALL	($0.00010) *2/1/18*	$0.00295 *2/1/18*	$0.00580 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00182 *2/1/18*	$0.00000 *2/1/18*	$0.00157 *2/1/18*	$0.01443 *2/1/18*
R-4 Residential Space Heating Assistance *Last change*	10	ALL	($0.00010) *2/1/18*	$0.00295 *2/1/18*	$0.00580 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00182 *2/1/18*	$0.00000 *2/1/18*	$0.00157 *2/1/18*	$0.01443 *2/1/18*
G-1 General Service *Last change*	11	BOST	($0.00011) *2/1/18*	$0.00407 *2/1/18*	$0.00803 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00251 *2/1/18*	$0.00000 *2/1/18*	$0.00217 *2/1/18*	$0.01907 *2/1/18*
G-2 General Service *Last change*	12	BOST	($0.00005) *2/1/18*	$0.00250 *2/1/18*	$0.00493 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00154 *2/1/18*	$0.00000 *2/1/18*	$0.00134 *2/1/18*	$0.01265 *2/1/18*
G-3 General Service *Last change*	13	BOST	($0.00003) *2/1/18*	$0.00147 *2/1/18*	$0.00290 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00091 *2/1/18*	$0.00000 *2/1/18*	$0.00078 *2/1/18*	$0.00841 *2/1/18*
T-1 General Service Optional Time-of-Use *Last change*	14	BOST	($0.00011) *2/1/18*	$0.00407 *2/1/18*	$0.00803 *2/1/18*	$0.00004 *2/1/18*	$0.00236 *1/1/18*	$0.00251 *2/1/18*	$0.00000 *2/1/18*	$0.00217 *2/1/18*	$0.01907 *2/1/18*
T-2 General Service Time-of-Use *Last change*	15	BOST	($0.00005) *2/1/18*	$0.00250 *2/1/18*	$0.00493 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00154 *2/1/18*	$0.00000 *2/1/18*	$0.00134 *2/1/18*	$0.01265 *2/1/18*
WR MWRA *Last Change*	16	BOST	($0.00003) *2/1/18*	$0.00147 *2/1/18*	$0.00290 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00091 *2/1/18*	$0.00000 *2/1/18*	$0.00078 *2/1/18*	$0.00841 *2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

EASTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
G-0 General (Non-Demand) *Last Change*	18	CAMB	($0.00006) *2/1/18*	$0.00209 *2/1/18*	$0.00411 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00129 *2/1/18*	$0.00000 *2/1/18*	$0.00111 *2/1/18*	$0.01092 *2/1/18*
G-1 General *Last Change*	19	CAMB	($0.00006) *2/1/18*	$0.00209 *2/1/18*	$0.00411 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00129 *2/1/18*	$0.00000 *2/1/18*	$0.00111 *2/1/18*	$0.01092 *2/1/18*
G-2 Large General TOU Secondary Service *Last Change*	20	CAMB	($0.00005) *2/1/18*	$0.00147 *2/1/18*	$0.00290 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00091 *2/1/18*	$0.00000 *2/1/18*	$0.00079 *2/1/18*	$0.00840 *2/1/18*
G-3 Large General TOU 13.8 kV Service *Last Change*	21	CAMB	($0.00003) *2/1/18*	$0.00079 *2/1/18*	$0.00156 *2/1/18*	$0.00001 *2/1/18*	$0.00236 *1/1/18*	$0.00049 *2/1/18*	$0.00000 *2/1/18*	$0.00042 *2/1/18*	$0.00560 *2/1/18*
G-4 Optional General TOU *Last Change*	22	CAMB	($0.00008) *2/1/18*	$0.00135 *2/1/18*	$0.00266 *2/1/18*	$0.00001 *2/1/18*	$0.00236 *1/1/18*	$0.00083 *2/1/18*	$0.00000 *2/1/18*	$0.00072 *2/1/18*	$0.00785 *2/1/18*
G-5 Commercial Space Heating (closed) *Last Change*	23	CAMB	($0.00009) *2/1/18*	$0.00141 *2/1/18*	$0.00279 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00087 *2/1/18*	$0.00000 *2/1/18*	$0.00075 *2/1/18*	$0.00811 *2/1/18*
G-6 Optional General TOU (Non-Demand) *Last Change*	24	CAMB	($0.00006) *2/1/18*	$0.00209 *2/1/18*	$0.00411 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00129 *2/1/18*	$0.00000 *2/1/18*	$0.00111 *2/1/18*	$0.01092 *2/1/18*
G-1 General *Last Change*	29	SOUTH	($0.00008) *2/1/18*	$0.00230 *2/1/18*	$0.00453 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00142 *2/1/18*	$0.00000 *2/1/18*	$0.00123 *2/1/18*	$0.01178 *2/1/18*
G-2 Medium General TOU *Last Change*	30	SOUTH	($0.00005) *2/1/18*	$0.00138 *2/1/18*	$0.00273 *2/1/18*	$0.00001 *2/1/18*	$0.00236 *1/1/18*	$0.00085 *2/1/18*	$0.00000 *2/1/18*	$0.00074 *2/1/18*	$0.00802 *2/1/18*
G-3 Large General TOU *Last Change*	31	SOUTH	($0.00004) *2/1/18*	$0.00091 *2/1/18*	$0.00180 *2/1/18*	$0.00001 *2/1/18*	$0.00236 *1/1/18*	$0.00056 *2/1/18*	$0.00000 *2/1/18*	$0.00049 *2/1/18*	$0.00609 *2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

EASTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
G-4 General Power *Last Change*	32	SOUTH	($0.00008) *2/1/18*	$0.00202 *2/1/18*	$0.00399 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00125 *2/1/18*	$0.00000 *2/1/18*	$0.00108 *2/1/18*	$0.01064 *2/1/18*
G-5 Commercial Space Heating (Closed) *Last Change*	33	SOUTH	($0.00014) *2/1/18*	$0.00245 *2/1/18*	$0.00483 *2/1/18*	$0.00003 *2/1/18*	$0.00236 *1/1/18*	$0.00151 *2/1/18*	$0.00000 *2/1/18*	$0.00131 *2/1/18*	$0.01235 *2/1/18*
G-6 All Electric School (Closed) *Last Change*	34	SOUTH	($0.00007) *2/1/18*	$0.00114 *2/1/18*	$0.00225 *2/1/18*	$0.00001 *2/1/18*	$0.00236 *1/1/18*	$0.00070 *2/1/18*	$0.00000 *2/1/18*	$0.00061 *2/1/18*	$0.00700 *2/1/18*
G-7 Optional General TOU *Last Change*	35	SOUTH	($0.00008) *2/1/18*	$0.00230 *2/1/18*	$0.00453 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00142 *2/1/18*	$0.00000 *2/1/18*	$0.00123 *2/1/18*	$0.01178 *2/1/18*
S-1 Street and Security Lighting *Last Change*	44	ALL	($0.00024) *2/1/18*	$0.00204 *2/1/18*	$0.00402 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00126 *2/1/18*	$0.00000 *2/1/18*	$0.00109 *2/1/18*	$0.01055 *2/1/18*
S-2 Street and Security - Customer Owned *Last Change*	45	ALL	($0.00024) *2/1/18*	$0.00204 *2/1/18*	$0.00402 *2/1/18*	$0.00002 *2/1/18*	$0.00236 *1/1/18*	$0.00126 *2/1/18*	$0.00000 *2/1/18*	$0.00109 *2/1/18*	$0.01055 *2/1/18*

PART C - BASIC SERVICE *
All Rates are in $/kWh across all hours and usage levels

EASTERN MASSACHUSETTS																
Sector	Rate Class	Type	Zone	01-Jan-18	01-Feb-18	01-Mar-18	01-Apr-18	01-May-18	01-Jun-18	01-Jul-18	01-Aug-18	01-Sep-18	01-Oct-18	01-Nov-18	01-Dec-18	*Last Change*
Residential	R-1, R-2, R-3, R-4	Fixed	ALL	$0.12881	$0.12888	$0.12888	$0.12888	$0.12888	$0.12888	$0.11397	$0.11397	$0.11397	$0.11397	$0.11397	$0.11397	*7/1/18*
		Variable	ALL	$0.14875	$0.15312	$0.12565	$0.11690	$0.11172	$0.10670	$0.10350	$0.10383	$0.11091	$0.12008	$0.11931	$0.13302	*7/1/18*
Small C&I	G-0(CAMB), G-1(BOST/CAMB/SOUTH), G-2(BOST), G-4(CAMB/SOUTH), G-5(CAMB/SOUTH), G-6(CAMB/SOUTH), G-7(SOUTH), T-1(BOST)	Fixed	ALL	$0.12685	$0.12692	$0.12692	$0.12692	$0.12692	$0.12692	$0.11403	$0.11403	$0.11403	$0.11403	$0.11403	$0.11403	*7/1/18*
		Variable	ALL	$0.15031	$0.15425	$0.12415	$0.11237	$0.10771	$0.10586	$0.10708	$0.10617	$0.10900	$0.11430	$0.11683	$0.13414	*7/1/18*
Large C&I	G-2(CAMB), G-3(BOST/CAMB), T-2(BOST)	Fixed	NEMA	$0.14632	$0.14639	$0.14639	$0.11492	$0.11492	$0.11492	$0.11498	$0.11498	$0.11498	$0.13260	$0.13260	$0.13260	*10/1/18*
		Variable	NEMA	$0.15155	$0.15692	$0.13014	$0.12720	$0.11860	$0.09992	$0.11476	$0.11248	$0.11812	$0.12290	$0.12523	$0.14783	*10/1/18*
Large C&I	G-2(SOUTH), G-3(BOST/SOUTH), T-2 (BOST)	Fixed	SEMA	$0.11933	$0.11940	$0.11940	$0.09068	$0.09068	$0.09068	$0.10398	$0.10398	$0.10398	$0.12266	$0.12266	$0.12266	*10/1/18*
		Variable	SEMA	$0.12772	$0.12891	$0.10171	$0.08782	$0.08132	$0.10196	$0.10405	$0.10277	$0.10522	$0.11362	$0.11649	$0.13722	*10/1/18*
St. Lighting	S-1, S-2	Fixed	ALL	$0.12685	$0.12692	$0.12692	$0.12692	$0.12692	$0.12692	$0.11403	$0.11403	$0.11403	$0.11403	$0.11403	$0.11403	*7/1/18*
		Variable	ALL	$0.15031	$0.15425	$0.12415	$0.11237	$0.10771	$0.10586	$0.10708	$0.10617	$0.10900	$0.11430	$0.11683	$0.13414	*7/1/18*

* Includes the Basic Service Bad Debt Cost of $0.00130 and NSTAR Green Cost of $0.00090

Western Massachusetts Electric Company
d/b/a Eversource Energy
Summary of Electric Delivery Service Rates
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Rate	MDPU No	Blocks	Distribution	Revenue Decoupling Mechanism	Pension/ PBOP Adj. Mechanism	Residential Assistant Adj. Clause	Energy Efficiency (EEPCA)	Solar Program Cost Adj.	Basic Svc. Cost Adj. (True Up)	Net Metering Surcharge	Transition Charge	Transmission	Energy Efficiency (DSM)	Renewable Charge	AG Consultant Expenses	Storm Recovery Adj.	Long-term Ren Contract (LRCA)	Total Delivery
R-1	1000W	Customer	$ 6.00															$ 6.00
		kWh <600	$ 0.04286	$ (0.00038)														$ 0.04248
		kWh >600	$ 0.05286	$ (0.00038)														$ 0.05248
		All kWh			$0.00143	$0.00854	$0.01590	$(0.00016)	$ 0.00027	$ 0.00559	$(0.00171)	$0.02797	$0.00250	$ 0.00050	$0.00004	$0.00299	$ 0.00331	$ 0.06717
Last Change			6/1/13	2/1/17	1/1/18	1/1/18	7/1/17	1/1/18	1/1/18	1/1/18	1/1/18	1/1/18	3/1/98	1/1/03	1/1/18	1/1/18	1/1/18	
R-2	1034S	Customer	$ 6.00															$ 6.00
		kWh <600	$ 0.04286	$ (0.00038)														$ 0.04248
32% discount on total bill		kWh >600	$ 0.05286	$ (0.00038)														$ 0.05248
		All kWh			$0.00143	$0.00854	$0.00212	$(0.00016)	$ 0.00027	$ 0.00559	$(0.00171)	$0.02797	$0.00250	$ 0.00050	$0.00004	$0.00299	$ 0.00331	$ 0.05339
Last Change			6/1/13	2/1/17	1/1/18	1/1/18	7/1/17	1/1/18	1/1/18	1/1/18	1/1/18	1/1/18	3/1/98	1/1/03	1/1/18	1/1/18	1/1/18	
R-3	1001W	Customer	$ 6.00															$ 6.00
		kWh <1,000	$ 0.03989	$ (0.00033)														$ 0.03956
		kWh >1,000	$ 0.04989	$ (0.00033)														$ 0.04956
		All kWh			$0.00127	$0.00796	$0.01590	$(0.00015)	$ 0.00025	$ 0.00521	$(0.00171)	$0.02820	$0.00250	$ 0.00050	$0.00004	$0.00279	$ 0.00331	$ 0.06607
Last Change			6/1/13	2/1/17	1/1/18	1/1/18	7/1/17	1/1/18	1/1/18	1/1/18	1/1/18	1/1/18	3/1/98	1/1/03	1/1/18	1/1/18	1/1/18	
R-4	1035S	Customer	$ 6.00															$ 6.00
		kWh <1,000	$ 0.03989	$ (0.00033)														$ 0.03956
32% discount on total bill		kWh >1,000	$ 0.04989	$ (0.00033)														$ 0.04956
		All kWh			$0.00127	$0.00796	$0.00212	$(0.00015)	$ 0.00025	$ 0.00521	$(0.00171)	$0.02820	$0.00250	$ 0.00050	$0.00004	$0.00279	$ 0.00331	$ 0.05229
Last Change			6/1/13	2/1/17	1/1/18	1/1/18	7/1/17	1/1/18	1/1/18	1/1/18	1/1/18	1/1/18	3/1/98	1/1/03	1/1/18	1/1/18	1/1/18	
23	1002W	Customer	$ 16.00															$ 16.00
		All kWh	$ 0.02545	$ (0.00029)	$0.00095	$0.00646	$0.00725	$(0.00012)	$ 0.00020	$ 0.00423	$(0.00171)	$0.02121	$0.00250	$ 0.00050	$0.00003	$0.00226	$ 0.00331	$ 0.07223
Last Change			6/1/13	2/1/17	1/1/18	1/1/18	7/1/17	1/1/18	1/1/18	1/1/18	1/1/18	1/1/18	3/1/98	1/1/03	1/1/18	1/1/18	1/1/18	
24	1003W	Customer	$ 60.00															$ 60.00
		All kWh	$ 0.00520	$ (0.00029)	$0.00095	$0.00646	$0.00725	$(0.00012)	$ 0.00020	$ 0.00423	$(0.00171)	$ -	$0.00250	$ 0.00050	$0.00003	$0.00226	$ 0.00331	$ 0.03077
		Demand > 2kW	$ 4.08									$ 3.52						$7.60
Last Change			6/1/13	2/1/17	1/1/18	1/1/18	7/1/17	1/1/18	1/1/18	1/1/18	1/1/18	1/1/18	3/1/98	1/1/03	1/1/18	1/1/18	1/1/18	
G-0	1004W	Customer Without Meter	$ 15.00															$ 15.00
		Customer With Meter	$ 30.00															$ 30.00
		All kWh	$ 0.00178	$ (0.00029)	$0.00095	$0.00646	$0.00725	$(0.00012)	$ 0.00020	$ 0.00423	$(0.00171)	$ -	$0.00250	$ 0.00050	$0.00003	$0.00226	$ 0.00331	$ 0.02735
		Demand > 2kW	$ 9.05									$ 7.52						$16.57
Last Change			6/1/13	2/1/17	1/1/18	1/1/18	7/1/17	1/1/18	1/1/18	1/1/18	1/1/18	1/1/18	3/1/98	1/1/03	1/1/18	1/1/18	1/1/18	
T-0	1005W	Customer	$ 30.00															$ 30.00
		On-Peak kWh	$ 0.00284	$ (0.00029)							$(0.00171)							$ 0.00084
		Off-Peak kWh	$ 0.00076	$ (0.00029)							$(0.00171)							$ (0.00124)
		All kWh			$0.00095	$0.00646	$0.00725	$(0.00012)	$ 0.00020	$ 0.00423		$ -	$0.00250	$ 0.00050	$0.00003	$0.00226	$ 0.00331	$ 0.02757
		Demand > 2kW	$ 9.05									$ 10.13						$19.18
Last Change			6/1/13	2/1/17	1/1/18	1/1/18	7/1/17	1/1/18	1/1/18	1/1/18	1/1/18	1/1/18	3/1/98	1/1/03	1/1/18	1/1/18	1/1/18	
G-2	1006W	Customer	$ 325.00															$ 325.00
		All kWh	$ 0.00178	$ (0.00020)	$0.00096	$0.00467	$0.00725	$(0.00009)	$ 0.00015	$ 0.00306	$(0.00171)	$ -	$0.00250	$ 0.00050	$0.00002	$0.00163	$ 0.00331	$ 0.02383
		Demand < 50kW	$ 1.69									$ 7.00						$8.69
		Demand > 50kW	$ 7.94									$ 7.00						$14.94
Last Change			6/1/13	2/1/17	1/1/18	1/1/18	7/1/17	1/1/18	1/1/18	1/1/18	1/1/18	1/1/18	3/1/98	1/1/03	1/1/18	1/1/18	1/1/18	

Issued per Order in D.P.U. 17-157
Dated December 28, 2017

For Consumption on and
After January 1, 2018

Western Massachusetts Electric Company
d/b/a Eversource Energy
Summary of Electric Delivery Service Rates
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Rate	MDPU No.	Blocks	Distribution	Revenue Decoupling Mechanism	Pension/ PBOP Adj. Mechanism	Residential Assistant Adj. Clause	Energy Efficiency (EEPCA)	Solar Program Cost Adj.	Basic Svc. Cost Adj. (True Up)	Net Metering Surcharge	Transition Charge	Transmission		Energy Efficiency (DSM)	Renewable Charge	AG Consultant Expenses	Storm Recovery Adj.	Long-term Ren Contract (LRCA)	Total Delivery
T-4	1007W	Customer	$ 325.00																$ 325.00
		On-Peak kWh	$ 0.00267	$ (0.00020)							$ (0.00171)	$ -							$ 0.00076
		Off-Peak kWh	$ 0.00076	$ (0.00020)							$ (0.00171)	$ -							$ (0.00115)
		All kWh			$0.00096	$0.00467	$0.00725	$ (0.00009)	$ 0.00015	$ 0.00306				$0.00250	$ 0.00050	$0.00002	$0.00163	$ 0.00331	$ 0.02396
		Demand < 50kW	$ 1.69								$ -	$ 7.85							$ 9.54
		Demand > 50kW	$ 7.94								$ -	$ 7.85							$ 15.79
Last Change			6/1/13	2/1/17	1/1/18	1/1/18	7/1/17	1/1/18	1/1/18	1/1/18	1/1/18	1/1/18		3/1/98	1/1/03	1/1/18	1/1/18	1/1/18	
T-2	1008W	Customer 350<1000kW	$ 700.00																$ 700.00
		Customer 1000<1500kW	$ 1,500.00																$ 1,500.00
		Customer 1500<2500kW	$ 2,500.00																$ 2,500.00
		On-Peak kWh	$ 0.00257	$ (0.00014)							$ (0.00171)	$ -							$ 0.00072
		Off-Peak kWh	$ 0.00076	$ (0.00014)							$ (0.00171)	$ -							$ (0.00109)
		All kWh			$0.00045	$0.00300	$0.00725	$ (0.00006)	$ 0.00009	$ 0.00197		$ -		$0.00250	$ 0.00050	$0.00001	$0.00105	$ 0.00331	$ 0.02007
		On-Peak Demand	$ 6.31									$ 9.02							$15.33
Last Change			6/1/13	2/1/17	1/1/18	1/1/18	7/1/17	1/1/18	1/1/18	1/1/18	1/1/18	1/1/18		3/1/98	1/1/03	1/1/18	1/1/18	1/1/18	
T-5	1049B	Customer >2500kW	$ 3,500.00																$ 3,500.00
		On-Peak kWh	$ 0.00257	$ (0.00009)							$ (0.00171)								$ 0.00077
		Off-Peak kWh	$ 0.00076	$ (0.00009)							$ (0.00171)								$ (0.00104)
		All kWh			$0.00027	$0.00185	$0.00725	$ (0.00003)	$ 0.00006	$ 0.00121		$ -		$0.00250	$ 0.00050	$0.00001	$0.00065	$ 0.00331	$ 0.01758
		On-Peak Demand	$4.49									$ 7.55							$12.04
		Coincident Peak Demand											$ 11.87						
Last Change			6/1/13	2/1/17	1/1/18	1/1/18	7/1/17	1/1/18	1/1/18	1/1/18	1/1/18	1/1/18	1/1/18	3/1/98	1/1/03	1/1/18	1/1/18	1/1/18	
Street and Security Lighting																			
S-1	1009AA	For lamp, luminaire, pole and accessory charges		$ (0.00035)	$0.00569	$0.00769	$0.00725	$ (0.00014)	$ 0.00024	$ 0.00503	$ (0.00171)	$0.01493		$0.00250	$ 0.00050	$0.00004	$0.00269	$ 0.00331	$ 0.04767
S-2	1010AA	*See individual S-1 and S-2 tariffs*		$ (0.00035)	$0.00569	$0.00769	$0.00725	$ (0.00014)	$ 0.00024	$ 0.00503	$ (0.00171)	$0.01493		$0.00250	$ 0.00050	$0.00004	$0.00269	$ 0.00331	$ 0.04767
Last Change				2/1/17	1/1/18	1/1/18	7/1/17	1/1/18	1/1/18	1/1/18	1/1/18	1/1/18		3/1/98	1/1/03	1/1/18	1/1/18	1/1/18	
Basic Service*	1026BB		January	February	March	April	May	June	*Last Change*										
Residential	R-1, R-2, R-3, R-4	Fixed	$ 0.10486	$ 0.10486	$0.10486	$0.10486	$0.10486	$ 0.10486	1/1/18										
		Variable	$ 0.12646	$ 0.12620	$0.10031	$0.08865	$0.08565	$ 0.09148	1/1/18										
Small C&I	23, 24, G-0, T-0	Fixed	$ 0.11404	$ 0.11404	$0.11404	$0.11404	$0.11404	$ 0.11404	1/1/18										
		Variable	$ 0.13498	$ 0.13814	$0.11023	$0.09874	$0.09476	$ 0.09707	1/1/18										
Med&Lrg C&I	G-2, T-4, T-2, T-5	Fixed	$ 0.12241	$ 0.12241	$0.12241				1/1/18										
		Variable	$ 0.12988	$ 0.13128	$0.10482				1/1/18										
St. Lighting	S-1 & S-2	Fixed	$ 0.07359	$ 0.07359	$0.07359	$0.07359	$0.07359	$ 0.07359	1/1/18										
		Variable	$ 0.09779	$ 0.09604	$0.07090	$0.05463	$0.05057	$ 0.05076	1/1/18										

*Includes the Basic Service Cost Adjustment Factor of $ 0.00139.

Issued per Order in D.P.U. 17-157
Dated December 28, 2017

For Consumption on and
After January 1, 2018

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

WESTERN MASSACHUSETTS														
										Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
R-1 Residential	7	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.04372	$0.02694	$0.07066	$0.00075	($0.00171)	$0.02797	$0.00250	$0.01590	$0.01840	$0.00050	$0.11657
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
R-2 Residential Assistance	8	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.04372	$0.02694	$0.07066	$0.00075	($0.00171)	$0.02797	$0.00250	$0.00212	$0.00462	$0.00050	$0.10279
			Discount	36%										
Last change				*2/1/18*	2/1/18	2/1/18	2/1/18	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
R-3 Residential Space Heating	9	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.03835	$0.02294	$0.06129	$0.00064	($0.00171)	$0.02820	$0.00250	$0.01590	$0.01840	$0.00050	$0.10732
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
R-4 Residential Space Heating Assistance	10	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.03835	$0.02294	$0.06129	$0.00064	($0.00171)	$0.02820	$0.00250	$0.00212	$0.00462	$0.00050	$0.09354
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
23 Optional Water Heating	36	WMA	Customer	$17.00		$17.00								$17.00
			Energy (kWh)	$0.02399	$0.02152	$0.04551	$0.00057	($0.00171)	$0.02121	$0.00250	$0.00725	$0.00975	$0.00050	$0.07583
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
24 Optional Church	37	WMA	Customer	$65.00		$65.00								$65.00
			Demand (>2 kW)	$3.84		$3.84			$3.52					$7.36
			Energy (kWh)	$0.00490	$0.02152	$0.02642	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.03553
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
G-0 Small General Service	38	WMA	Customer (without meter)	$15.00		$15.00								$15.00
			Customer (with meter)	$30.00		$30.00								$30.00
			Demand (>2 kW)	$9.03		$9.03			$7.52					$16.55
			Energy (kWh)	$0.00177	$0.02152	$0.02329	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.03240
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
T-0 Small General Service TOU	39	WMA	Customer	$30.00		$30.00								$30.00
			Demand (>2 kW)	$9.10		$9.10			$10.13					$19.23
			Peak kWh	$0.00285	$0.02152	$0.02437	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.03348
			Off Peak kWh	$0.00076	$0.02152	$0.02228	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.03139
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

WESTERN MASSACHUSETTS														
										Energy Efficiency Charge (EEC)			Renewable	Total
Schedule	MDPU No.	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission	System Benefits	Recon. Factor	Total EEC	Energy	Delivery
G-2 Primary General Service	40	WMA	Customer	$353.00		$353.00								$353.00
			Demand (<=50 kW)	$1.61		$1.61			$7.00					$8.61
			Demand (>50 kW)	$7.57		$7.57			$7.00					$14.57
			Energy (kWh)	$0.00169	$0.01464	$0.01633	$0.00035	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.02522
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
T-4 Primary General Service TOU	41	WMA	Customer	$353.00		$353.00								$353.00
			Demand (<=50 kW)	$1.61		$1.61			$7.85					$9.46
			Demand (>50 kW)	$7.58		$7.58			$7.85					$15.43
			Peak kWh	$0.00255	$0.01464	$0.01719	$0.00035	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.02608
			Off Peak kWh	$0.00072	$0.01464	$0.01536	$0.00035	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.02425
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
T-2 Large Primary Service TOU	42	WMA	Customer (350<= kW < 1000 kW)	$760.00		$760.00								$760.00
			Customer (1000<= kW < 1500 kW)	$1,625.00		$1,625.00								$1,625.00
			Customer (1500<= kW < 2500 kW)	$2,700.00		$2,700.00								$2,700.00
			Demand (kW)	$6.22		$6.22			$9.02					$15.24
			Peak kWh	$0.00253	$0.01173	$0.01426	$0.00026	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.02306
			Off Peak kWh	$0.00074	$0.01173	$0.01247	$0.00026	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.02127
Last Change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
T-5 Extra Large Primary Service TOU	43	WMA	Customer	$3,800.00		$3,800.00								$3,800.00
			On Peak Demand	$4.44		$4.44			$7.55					$11.99
			Coincident Peak Demand						$11.87					$11.87
			Peak kWh	$0.00254	$0.00788	$0.01042	$0.00014	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.01910
			Off Peak kWh	$0.00075	$0.00788	$0.00863	$0.00014	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.01731
Last Change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
S-1 Street and Security Lighting	44	WMA	Fixture Charge	Per Rate Schedule		Per Rate Schedule								Per Rate Schedule
			kWh		$0.01823		$0.00037	($0.00171)	$0.01493	$0.00250	$0.00725	$0.00975	$0.00050	
Last Change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
S-2 Street and Security Lighting - Customer Owned	45	WMA	Per Watt	$0.01138		$0.01138								$0.01138
			kWh		$0.01823	$0.01823	$0.00037	($0.00171)	$0.01493	$0.00250	$0.00725	$0.00975	$0.00050	$0.04207
Last Change				*2/1/18*	*2/1/18*		*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

WESTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
R-1 Residential *Last change*	7	WMA	$0.00143 *2/1/18*	$0.01323 *2/1/18*	$0.00575 *2/1/18*	$0.00004 *2/1/18*	$0.00331 *1/1/18*	$0.00307 *2/1/18*	($0.00016) *2/1/18*	$0.00027 *2/1/18*	$0.02694 *2/1/18*
R-2 Residential Low Income *Last change*	8	WMA	$0.00143 *2/1/18*	$0.01323 *2/1/18*	$0.00575 *2/1/18*	$0.00004 *2/1/18*	$0.00331 *1/1/18*	$0.00307 *2/1/18*	($0.00016) *2/1/18*	$0.00027 *2/1/18*	$0.02694 *2/1/18*
R-3 Residential Space Heating *Last change*	9	WMA	$0.00140 *2/1/18*	$0.01086 *2/1/18*	$0.00472 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00252 *2/1/18*	($0.00013) *2/1/18*	$0.00023 *2/1/18*	$0.02294 *2/1/18*
R-4 Residential Space Heating Low Income *Last change*	10	WMA	$0.00140 *2/1/18*	$0.01086 *2/1/18*	$0.00472 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00252 *2/1/18*	($0.00013) *2/1/18*	$0.00023 *2/1/18*	$0.02294 *2/1/18*
23 Optional Water Heating *Last change*	36	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
24 Optional Church *Last change*	37	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
G-0 Small General Service *Last change*	38	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
T-0 Small General Service TOU *Last change*	39	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
G-2 Primary General Service *Last change*	40	WMA	$0.00063 *2/1/18*	$0.00638 *2/1/18*	$0.00277 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00148 *2/1/18*	($0.00008) *2/1/18*	$0.00013 *2/1/18*	$0.01464 *2/1/18*
T-4 Primary General Service TOU *Last change*	41	WMA	$0.00063 *2/1/18*	$0.00638 *2/1/18*	$0.00277 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00148 *2/1/18*	($0.00008) *2/1/18*	$0.00013 *2/1/18*	$0.01464 *2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

WESTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
T-2 Large Primary Service TOU	42	WMA	$0.00052	$0.00471	$0.00205	$0.00001	$0.00331	$0.00109	($0.00006)	$0.00010	$0.01173
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
T-5 Extra Large Primary Service TOU	43	WMA	$0.00032	$0.00253	$0.00110	$0.00001	$0.00331	$0.00059	($0.00003)	$0.00005	$0.00788
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
S-1 Street and Security Lighting	44	WMA	$0.00388	$0.00657	$0.00286	$0.00002	$0.00331	$0.00153	($0.00008)	$0.00014	$0.01823
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*
S-2 Street and Security Lighting - Customer Owned	45	WMA	$0.00388	$0.00657	$0.00286	$0.00002	$0.00331	$0.00153	($0.00008)	$0.00014	$0.01823
Last Change			*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*

PART C - BASIC SERVICE *
All Rates are in $/kWh across all hours and usage levels

WESTERN MASSACHUSETTS															
Sector	Class	Type	Zone	01-Jan-18	01-Feb-18	01-Mar-18	01-Apr-18	01-May-18	01-Jun-18	01-Jul-18	01-Aug-18	01-Sep-18	01-Oct-18	01-Nov-18	01-Dec-18
Residential	R-1, R-2, R-3, R-4	Fixed	ALL	$ 0.10486	$ 0.10503	$ 0.10503	$ 0.10503	$ 0.10503	$ 0.10503						
		Variable	ALL	$ 0.12646	$ 0.12637	$ 0.10048	$ 0.08882	$ 0.08582	$ 0.09165						
Small C&I	All classes otherwise not listed here	Fixed	ALL	$ 0.11404	$ 0.11421	$ 0.11421	$ 0.11421	$ 0.11421	$ 0.11421						
		Variable	ALL	$ 0.13498	$ 0.13831	$ 0.11040	$ 0.09891	$ 0.09493	$ 0.09724						
Large C&I	G-2, T-4, T-2, T-5	Fixed	WCMA	$ 0.12241	$ 0.12258	$ 0.12258									
		Variable	WCMA	$ 0.12988	$ 0.13145	$ 0.10499									
St. Lighting	S-1, S-2	Fixed	ALL	$ 0.07359	$ 0.07376	$ 0.07376	$ 0.07376	$ 0.07376	$ 0.07376						
		Variable	ALL	$ 0.09779	$ 0.09621	$ 0.07107	$ 0.05480	$ 0.05074	$ 0.05093						

* Includes the Basic Service Bad Debt Cost of $0.00156

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

WESTERN MASSACHUSETTS														
										Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
R-1 Residential	7	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.04372	$0.02694	$0.07066	$0.00075	($0.00171)	$0.02797	$0.00250	$0.01590	$0.01840	$0.00050	$0.11657
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
R-2 Residential Assistance	8	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.04372	$0.02694	$0.07066	$0.00075	($0.00171)	$0.02797	$0.00250	$0.00212	$0.00462	$0.00050	$0.10279
			Discount	36%										
Last change				*2/1/18*	2/1/18	2/1/18	2/1/18	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
R-3 Residential Space Heating	9	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.03835	$0.02294	$0.06129	$0.00064	($0.00171)	$0.02820	$0.00250	$0.01590	$0.01840	$0.00050	$0.10732
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
R-4 Residential Space Heating Assistance	10	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.03835	$0.02294	$0.06129	$0.00064	($0.00171)	$0.02820	$0.00250	$0.00212	$0.00462	$0.00050	$0.09354
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
23 Optional Water Heating	36	WMA	Customer	$17.00		$17.00								$17.00
			Energy (kWh)	$0.02399	$0.02152	$0.04551	$0.00057	($0.00171)	$0.02121	$0.00250	$0.00725	$0.00975	$0.00050	$0.07583
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
24 Optional Church	37	WMA	Customer	$65.00		$65.00								$65.00
			Demand (>2 kW)	$3.84		$3.84			$3.52					$7.36
			Energy (kWh)	$0.00490	$0.02152	$0.02642	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.03553
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
G-0 Small General Service	38	WMA	Customer (without meter)	$15.00		$15.00								$15.00
			Customer (with meter)	$30.00		$30.00								$30.00
			Demand (>2 kW)	$9.03		$9.03			$7.52					$16.55
			Energy (kWh)	$0.00177	$0.02152	$0.02329	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.03240
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
T-0 Small General Service TOU	39	WMA	Customer	$30.00		$30.00								$30.00
			Demand (>2 kW)	$9.10		$9.10			$10.13					$19.23
			Peak kWh	$0.00285	$0.02152	$0.02437	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.03348
			Off Peak kWh	$0.00076	$0.02152	$0.02228	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.03139
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

WESTERN MASSACHUSETTS														
										Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
G-2 Primary General Service	40	WMA	Customer	$353.00		$353.00								$353.00
			Demand (<=50 kW)	$1.61		$1.61			$7.00					$8.61
			Demand (>50 kW)	$7.57		$7.57			$7.00					$14.57
			Energy (kWh)	$0.00169	$0.01464	$0.01633	$0.00035	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.02522
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
T-4 Primary General Service TOU	41	WMA	Customer	$353.00		$353.00								$353.00
			Demand (<=50 kW)	$1.61		$1.61			$7.85					$9.46
			Demand (>50 kW)	$7.58		$7.58			$7.85					$15.43
			Peak kWh	$0.00255	$0.01464	$0.01719	$0.00035	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.02608
			Off Peak kWh	$0.00072	$0.01464	$0.01536	$0.00035	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.02425
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
T-2 Large Primary Service TOU	42	WMA	Customer (350<= kW < 1000 kW)	$760.00		$760.00								$760.00
			Customer (1000<= kW < 1500 kW)	$1,625.00		$1,625.00								$1,625.00
			Customer (1500<= kW < 2500 kW)	$2,700.00		$2,700.00								$2,700.00
			Demand (kW)	$6.22		$6.22			$9.02					$15.24
			Peak kWh	$0.00253	$0.01173	$0.01426	$0.00026	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.02306
			Off Peak kWh	$0.00074	$0.01173	$0.01247	$0.00026	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.02127
Last Change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
T-5 Extra Large Primary Service TOU	43	WMA	Customer	$3,800.00		$3,800.00								$3,800.00
			On Peak Demand	$4.44		$4.44			$7.55					$11.99
			Coincident Peak Demand						$11.87					$11.87
			Peak kWh	$0.00254	$0.00788	$0.01042	$0.00014	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.01910
			Off Peak kWh	$0.00075	$0.00788	$0.00863	$0.00014	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.01731
Last Change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
S-1 Street and Security Lighting	44	WMA	Fixture Charge	Per Rate Schedule		Per Rate Schedule								Per Rate Schedule
			kWh		$0.01823		$0.00037	($0.00171)	$0.01493	$0.00250	$0.00725	$0.00975	$0.00050	
Last Change				*3/1/18*	*2/1/18*	*3/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*3/1/18*
S-2 Street and Security Lighting - Customer Owned	45	WMA	Per Watt	$0.01138		$0.01138								$0.01138
			kWh		$0.01823	$0.01823	$0.00037	($0.00171)	$0.01493	$0.00250	$0.00725	$0.00975	$0.00050	$0.04207
Last Change				*2/1/18*	*2/1/18*		*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

WESTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
R-1 Residential *Last change*	7	WMA	$0.00143 *2/1/18*	$0.01323 *2/1/18*	$0.00575 *2/1/18*	$0.00004 *2/1/18*	$0.00331 *1/1/18*	$0.00307 *2/1/18*	($0.00016) *2/1/18*	$0.00027 *2/1/18*	$0.02694 *2/1/18*
R-2 Residential Low Income *Last change*	8	WMA	$0.00143 *2/1/18*	$0.01323 *2/1/18*	$0.00575 *2/1/18*	$0.00004 *2/1/18*	$0.00331 *1/1/18*	$0.00307 *2/1/18*	($0.00016) *2/1/18*	$0.00027 *2/1/18*	$0.02694 *2/1/18*
R-3 Residential Space Heating *Last change*	9	WMA	$0.00140 *2/1/18*	$0.01086 *2/1/18*	$0.00472 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00252 *2/1/18*	($0.00013) *2/1/18*	$0.00023 *2/1/18*	$0.02294 *2/1/18*
R-4 Residential Space Heating Low Income *Last change*	10	WMA	$0.00140 *2/1/18*	$0.01086 *2/1/18*	$0.00472 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00252 *2/1/18*	($0.00013) *2/1/18*	$0.00023 *2/1/18*	$0.02294 *2/1/18*
23 Optional Water Heating *Last change*	36	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
24 Optional Church *Last change*	37	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
G-0 Small General Service *Last change*	38	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
T-0 Small General Service TOU *Last change*	39	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
G-2 Primary General Service *Last change*	40	WMA	$0.00063 *2/1/18*	$0.00638 *2/1/18*	$0.00277 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00148 *2/1/18*	($0.00008) *2/1/18*	$0.00013 *2/1/18*	$0.01464 *2/1/18*
T-4 Primary General Service TOU *Last change*	41	WMA	$0.00063 *2/1/18*	$0.00638 *2/1/18*	$0.00277 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00148 *2/1/18*	($0.00008) *2/1/18*	$0.00013 *2/1/18*	$0.01464 *2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

WESTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
T-2 Large Primary Service TOU *Last Change*	42	WMA	$0.00052 *2/1/18*	$0.00471 *2/1/18*	$0.00205 *2/1/18*	$0.00001 *2/1/18*	$0.00331 *1/1/18*	$0.00109 *2/1/18*	($0.00006) *2/1/18*	$0.00010 *2/1/18*	$0.01173 *2/1/18*
T-5 Extra Large Primary Service TOU *Last Change*	43	WMA	$0.00032 *2/1/18*	$0.00253 *2/1/18*	$0.00110 *2/1/18*	$0.00001 *2/1/18*	$0.00331 *1/1/18*	$0.00059 *2/1/18*	($0.00003) *2/1/18*	$0.00005 *2/1/18*	$0.00788 *2/1/18*
S-1 Street and Security Lighting *Last Change*	44	WMA	$0.00388 *2/1/18*	$0.00657 *2/1/18*	$0.00286 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00153 *2/1/18*	($0.00008) *2/1/18*	$0.00014 *2/1/18*	$0.01823 *2/1/18*
S-2 Street and Security Lighting - Customer Owned *Last Change*	45	WMA	$0.00388 *2/1/18*	$0.00657 *2/1/18*	$0.00286 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00153 *2/1/18*	($0.00008) *2/1/18*	$0.00014 *2/1/18*	$0.01823 *2/1/18*

PART C - BASIC SERVICE *
All Rates are in $/kWh across all hours and usage levels

WESTERN MASSACHUSETTS																	
Sector	Class	Type	Zone	01-Jan-18	01-Feb-18	01-Mar-18	01-Apr-18	01-May-18	01-Jun-18	01-Jul-18	01-Aug-18	01-Sep-18	01-Oct-18	01-Nov-18	01-Dec-18
Residential	R-1, R-2, R-3, R-4	Fixed	ALL	$ 0.10486	$ 0.10503	$ 0.10503	$ 0.10503	$ 0.10503	$ 0.10503						
		Variable	ALL	$ 0.12646	$ 0.12637	$ 0.10048	$ 0.08882	$ 0.08582	$ 0.09165						
Small C&I	All classes otherwise not listed here	Fixed	ALL	$ 0.11404	$ 0.11421	$ 0.11421	$ 0.11421	$ 0.11421	$ 0.11421						
		Variable	ALL	$ 0.13498	$ 0.13831	$ 0.11040	$ 0.09891	$ 0.09493	$ 0.09724						
Large C&I	G-2, T-4, T-2, T-5	Fixed	WCMA	$ 0.12241	$ 0.12258	$ 0.12258									
		Variable	WCMA	$ 0.12988	$ 0.13145	$ 0.10499									
St. Lighting	S-1, S-2	Fixed	ALL	$ 0.07359	$ 0.07376	$ 0.07376	$ 0.07376	$ 0.07376	$ 0.07376						
		Variable	ALL	$ 0.09779	$ 0.09621	$ 0.07107	$ 0.05480	$ 0.05074	$ 0.05093						

* Includes the Basic Service Bad Debt Cost of $0.00156

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

WESTERN MASSACHUSETTS														
										Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
R-1 Residential	7	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.04372	$0.02694	$0.07066	$0.00075	($0.00171)	$0.02797	$0.00250	$0.01590	$0.01840	$0.00050	$0.11657
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
R-2 Residential Assistance	8	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.04372	$0.02694	$0.07066	$0.00075	($0.00171)	$0.02797	$0.00250	$0.00212	$0.00462	$0.00050	$0.10279
			Discount	36%										
Last change				*2/1/18*	2/1/18	2/1/18	2/1/18	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
R-3 Residential Space Heating	9	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.03835	$0.02294	$0.06129	$0.00064	($0.00171)	$0.02820	$0.00250	$0.01590	$0.01840	$0.00050	$0.10732
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
R-4 Residential Space Heating Assistance	10	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.03835	$0.02294	$0.06129	$0.00064	($0.00171)	$0.02820	$0.00250	$0.00212	$0.00462	$0.00050	$0.09354
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
23 Optional Water Heating	36	WMA	Customer	$17.00		$17.00								$17.00
			Energy (kWh)	$0.02399	$0.02152	$0.04551	$0.00057	($0.00171)	$0.02121	$0.00250	$0.00725	$0.00975	$0.00050	$0.07583
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
24 Optional Church	37	WMA	Customer	$65.00		$65.00								$65.00
			Demand (>2 kW)	$3.84		$3.84			$3.52					$7.36
			Energy (kWh)	$0.00490	$0.02152	$0.02642	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.03553
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
G-0 Small General Service	38	WMA	Customer (without meter)	$15.00		$15.00								$15.00
			Customer (with meter)	$30.00		$30.00								$30.00
			Demand (>2 kW)	$9.03		$9.03			$7.52					$16.55
			Energy (kWh)	$0.00177	$0.02152	$0.02329	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.03240
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
T-0 Small General Service TOU	39	WMA	Customer	$30.00		$30.00								$30.00
			Demand (>2 kW)	$9.10		$9.10			$10.13					$19.23
			Peak kWh	$0.00285	$0.02152	$0.02437	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.03348
			Off Peak kWh	$0.00076	$0.02152	$0.02228	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.03139
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

WESTERN MASSACHUSETTS														
										Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
G-2 Primary General Service	40	WMA	Customer	$353.00		$353.00								$353.00
			Demand (<=50 kW)	$1.61		$1.61			$7.00					$8.61
			Demand (>50 kW)	$7.57		$7.57			$7.00					$14.57
			Energy (kWh)	$0.00169	$0.01464	$0.01633	$0.00035	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.02522
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
T-4 Primary General Service TOU	41	WMA	Customer	$353.00		$353.00								$353.00
			Demand (<=50 kW)	$1.61		$1.61			$7.85					$9.46
			Demand (>50 kW)	$7.58		$7.58			$7.85					$15.43
			Peak kWh	$0.00255	$0.01464	$0.01719	$0.00035	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.02608
			Off Peak kWh	$0.00072	$0.01464	$0.01536	$0.00035	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.02425
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
T-2 Large Primary Service TOU	42	WMA	Customer (350<= kW < 1000 kW)	$760.00		$760.00								$760.00
			Customer (1000<= kW < 1500 kW)	$1,625.00		$1,625.00								$1,625.00
			Customer (1500<= kW < 2500 kW)	$2,700.00		$2,700.00								$2,700.00
			Demand (kW)	$6.22		$6.22			$9.02					$15.24
			Peak kWh	$0.00253	$0.01173	$0.01426	$0.00026	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.02306
			Off Peak kWh	$0.00074	$0.01173	$0.01247	$0.00026	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.02127
Last Change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
T-5 Extra Large Primary Service TOU	43	WMA	Customer	$3,800.00		$3,800.00								$3,800.00
			On Peak Demand	$4.44		$4.44			$7.55					$11.99
			Coincident Peak Demand						$11.87					$11.87
			Peak kWh	$0.00254	$0.00788	$0.01042	$0.00014	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.01910
			Off Peak kWh	$0.00075	$0.00788	$0.00863	$0.00014	($0.00171)	$0.00000	$0.00250	$0.00725	$0.00975	$0.00050	$0.01731
Last Change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*
S-1 Street and Security Lighting	44	WMA	Fixture Charge	Per Rate Schedule		Per Rate Schedule								Per Rate Schedule
			kWh		$0.01823		$0.00037	($0.00171)	$0.01493	$0.00250	$0.00725	$0.00975	$0.00050	
Last Change				*3/1/18*	*2/1/18*	*3/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*3/1/18*
S-2 Street and Security Lighting - Customer Owned	45	WMA	Per Watt	$0.01138		$0.01138								$0.01138
			kWh		$0.01823	$0.01823	$0.00037	($0.00171)	$0.01493	$0.00250	$0.00725	$0.00975	$0.00050	$0.04207
Last Change				*2/1/18*	*2/1/18*		*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/17*	*7/1/17*	*1/1/03*	*2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

WESTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
R-1 Residential *Last change*	7	WMA	$0.00143 *2/1/18*	$0.01323 *2/1/18*	$0.00575 *2/1/18*	$0.00004 *2/1/18*	$0.00331 *1/1/18*	$0.00307 *2/1/18*	($0.00016) *2/1/18*	$0.00027 *2/1/18*	$0.02694 *2/1/18*
R-2 Residential Low Income *Last change*	8	WMA	$0.00143 *2/1/18*	$0.01323 *2/1/18*	$0.00575 *2/1/18*	$0.00004 *2/1/18*	$0.00331 *1/1/18*	$0.00307 *2/1/18*	($0.00016) *2/1/18*	$0.00027 *2/1/18*	$0.02694 *2/1/18*
R-3 Residential Space Heating *Last change*	9	WMA	$0.00140 *2/1/18*	$0.01086 *2/1/18*	$0.00472 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00252 *2/1/18*	($0.00013) *2/1/18*	$0.00023 *2/1/18*	$0.02294 *2/1/18*
R-4 Residential Space Heating Low Income *Last change*	10	WMA	$0.00140 *2/1/18*	$0.01086 *2/1/18*	$0.00472 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00252 *2/1/18*	($0.00013) *2/1/18*	$0.00023 *2/1/18*	$0.02294 *2/1/18*
23 Optional Water Heating *Last change*	36	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
24 Optional Church *Last change*	37	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
G-0 Small General Service *Last change*	38	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
T-0 Small General Service TOU *Last change*	39	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
G-2 Primary General Service *Last change*	40	WMA	$0.00063 *2/1/18*	$0.00638 *2/1/18*	$0.00277 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00148 *2/1/18*	($0.00008) *2/1/18*	$0.00013 *2/1/18*	$0.01464 *2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

WESTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
T-4 Primary General Service TOU *Last change*	41	WMA	$0.00063 *2/1/18*	$0.00638 *2/1/18*	$0.00277 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00148 *2/1/18*	($0.00008) *2/1/18*	$0.00013 *2/1/18*	$0.01464 *2/1/18*
T-2 Large Primary Service TOU *Last Change*	42	WMA	$0.00052 *2/1/18*	$0.00471 *2/1/18*	$0.00205 *2/1/18*	$0.00001 *2/1/18*	$0.00331 *1/1/18*	$0.00109 *2/1/18*	($0.00006) *2/1/18*	$0.00010 *2/1/18*	$0.01173 *2/1/18*
T-5 Extra Large Primary Service TOU *Last Change*	43	WMA	$0.00032 *2/1/18*	$0.00253 *2/1/18*	$0.00110 *2/1/18*	$0.00001 *2/1/18*	$0.00331 *1/1/18*	$0.00059 *2/1/18*	($0.00003) *2/1/18*	$0.00005 *2/1/18*	$0.00788 *2/1/18*
S-1 Street and Security Lighting *Last Change*	44	WMA	$0.00388 *2/1/18*	$0.00657 *2/1/18*	$0.00286 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00153 *2/1/18*	($0.00008) *2/1/18*	$0.00014 *2/1/18*	$0.01823 *2/1/18*
S-2 Street and Security Lighting - Customer Owned *Last Change*	45	WMA	$0.00388 *2/1/18*	$0.00657 *2/1/18*	$0.00286 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00153 *2/1/18*	($0.00008) *2/1/18*	$0.00014 *2/1/18*	$0.01823 *2/1/18*

PART C - BASIC SERVICE *
All Rates are in $/kWh across all hours and usage levels

				WESTERN MASSACHUSETTS												
Sector	Class	Type	Zone	01-Jan-18	01-Feb-18	01-Mar-18	01-Apr-18	01-May-18	01-Jun-18	01-Jul-18	01-Aug-18	01-Sep-18	01-Oct-18	01-Nov-18	01-Dec-18	*Last change*
Residential	R-1, R-2, R-3, R-4	Fixed	ALL	$ 0.10486	$ 0.10503	$ 0.10503	$ 0.10503	$ 0.10503	$ 0.10503							*2/1/18*
		Variable	ALL	$ 0.12646	$ 0.12637	$ 0.10048	$ 0.08882	$ 0.08582	$ 0.09165							*2/1/18*
Small C&I	All classes otherwise not listed here	Fixed	ALL	$ 0.11404	$ 0.11421	$ 0.11421	$ 0.11421	$ 0.11421	$ 0.11421							*2/1/18*
		Variable	ALL	$ 0.13498	$ 0.13831	$ 0.11040	$ 0.09891	$ 0.09493	$ 0.09724							*2/1/18*
Large C&I	G-2, T-4, T-2, T-5	Fixed	WCMA	$ 0.12241	$ 0.12258	$ 0.12258	$ 0.09091	$ 0.09091	$ 0.09091							*4/1/18*
		Variable	WCMA	$ 0.12988	$ 0.13145	$ 0.10499	$ 0.09695	$ 0.08871	$ 0.08733							*4/1/18*
St. Lighting	S-1, S-2	Fixed	ALL	$ 0.07359	$ 0.07376	$ 0.07376	$ 0.07376	$ 0.07376	$ 0.07376							*2/1/18*
		Variable	ALL	$ 0.09779	$ 0.09621	$ 0.07107	$ 0.05480	$ 0.05074	$ 0.05093							*2/1/18*

* Includes the Basic Service Bad Debt Cost of $0.00156

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

WESTERN MASSACHUSETTS

Schedule	MDPU No.	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission	Energy Efficiency Charge (EEC) System Benefits	Energy Efficiency Charge (EEC) Recon. Factor	Energy Efficiency Charge (EEC) Total EEC	Renewable Energy	Total Delivery
R-1 Residential	7	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.04372	$0.02694	$0.07066	$0.00075	($0.00171)	$0.02797	$0.00250	$0.01402	$0.01652	$0.00050	$0.11469
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
R-2 Residential Assistance	8	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.04372	$0.02694	$0.07066	$0.00075	($0.00171)	$0.02797	$0.00250	$0.00065	$0.00315	$0.00050	$0.10132
			Discount	36%										
Last change				*2/1/18*	2/1/18	2/1/18	2/1/18	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
R-3 Residential Space Heating	9	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.03835	$0.02294	$0.06129	$0.00064	($0.00171)	$0.02820	$0.00250	$0.01402	$0.01652	$0.00050	$0.10544
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
R-4 Residential Space Heating Assistance	10	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.03835	$0.02294	$0.06129	$0.00064	($0.00171)	$0.02820	$0.00250	$0.00065	$0.00315	$0.00050	$0.09207
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
23 Optional Water Heating	36	WMA	Customer	$17.00		$17.00								$17.00
			Energy (kWh)	$0.02399	$0.02152	$0.04551	$0.00057	($0.00171)	$0.02121	$0.00250	$0.00972	$0.01222	$0.00050	$0.07830
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
24 Optional Church	37	WMA	Customer	$65.00		$65.00								$65.00
			Demand (>2 kW)	$3.84		$3.84			$3.52					$7.36
			Energy (kWh)	$0.00490	$0.02152	$0.02642	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.03800
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-0 Small General Service	38	WMA	Customer (without meter)	$15.00		$15.00								$15.00
			Customer (with meter)	$30.00		$30.00								$30.00
			Demand (>2 kW)	$9.03		$9.03			$7.52					$16.55
			Energy (kWh)	$0.00177	$0.02152	$0.02329	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.03487
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
T-0 Small General Service TOU	39	WMA	Customer	$30.00		$30.00								$30.00
			Demand (>2 kW)	$9.10		$9.10			$10.13					$19.23
			Peak kWh	$0.00285	$0.02152	$0.02437	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.03595
			Off Peak kWh	$0.00076	$0.02152	$0.02228	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.03386
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

WESTERN MASSACHUSETTS														
										Energy Efficiency Charge (EEC)			Renewable	Total
Schedule	MDPU No.	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission	System Benefits	Recon. Factor	Total EEC	Energy	Delivery
G-2 Primary General Service	40	WMA	Customer	$353.00		$353.00								$353.00
			Demand (<=50 kW)	$1.61		$1.61			$7.00					$8.61
			Demand (>50 kW)	$7.57		$7.57			$7.00					$14.57
			Energy (kWh)	$0.00169	$0.01464	$0.01633	$0.00035	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.02769
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
T-4 Primary General Service TOU	41	WMA	Customer	$353.00		$353.00								$353.00
			Demand (<=50 kW)	$1.61		$1.61			$7.85					$9.46
			Demand (>50 kW)	$7.58		$7.58			$7.85					$15.43
			Peak kWh	$0.00255	$0.01464	$0.01719	$0.00035	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.02855
			Off Peak kWh	$0.00072	$0.01464	$0.01536	$0.00035	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.02672
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
T-2 Large Primary Service TOU	42	WMA	Customer (350<= kW < 1000 kW)	$760.00		$760.00								$760.00
			Customer (1000<= kW < 1500 kW)	$1,625.00		$1,625.00								$1,625.00
			Customer (1500<= kW < 2500 kW)	$2,700.00		$2,700.00								$2,700.00
			Demand (kW)	$6.22		$6.22			$9.02					$15.24
			Peak kWh	$0.00253	$0.01173	$0.01426	$0.00026	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.02553
			Off Peak kWh	$0.00074	$0.01173	$0.01247	$0.00026	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.02374
Last Change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
T-5 Extra Large Primary Service TOU	43	WMA	Customer	$3,800.00		$3,800.00								$3,800.00
			On Peak Demand	$4.44		$4.44			$7.55					$11.99
			Coincident Peak Demand						$11.87					$11.87
			Peak kWh	$0.00254	$0.00788	$0.01042	$0.00014	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.02157
			Off Peak kWh	$0.00075	$0.00788	$0.00863	$0.00014	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.01978
Last Change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
S-1 Street and Security Lighting	44	WMA	Fixture Charge	Per Rate Schedule		Per Rate Schedule								Per Rate Schedule
			kWh		$0.01823		$0.00037	($0.00171)	$0.01493	$0.00250	$0.00972	$0.01222	$0.00050	
Last Change				*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
S-2 Street and Security Lighting - Customer Owned	45	WMA	Per Watt	$0.01141		$0.01141								$0.01141
			kWh		$0.01823	$0.01823	$0.00037	($0.00171)	$0.01493	$0.00250	$0.00972	$0.01222	$0.00050	$0.04454
Last Change				*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

WESTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
R-1 Residential *Last change*	7	WMA	$0.00143 *2/1/18*	$0.01323 *2/1/18*	$0.00575 *2/1/18*	$0.00004 *2/1/18*	$0.00331 *1/1/18*	$0.00307 *2/1/18*	($0.00016) *2/1/18*	$0.00027 *2/1/18*	$0.02694 *2/1/18*
R-2 Residential Low Income *Last change*	8	WMA	$0.00143 *2/1/18*	$0.01323 *2/1/18*	$0.00575 *2/1/18*	$0.00004 *2/1/18*	$0.00331 *1/1/18*	$0.00307 *2/1/18*	($0.00016) *2/1/18*	$0.00027 *2/1/18*	$0.02694 *2/1/18*
R-3 Residential Space Heating *Last change*	9	WMA	$0.00140 *2/1/18*	$0.01086 *2/1/18*	$0.00472 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00252 *2/1/18*	($0.00013) *2/1/18*	$0.00023 *2/1/18*	$0.02294 *2/1/18*
R-4 Residential Space Heating Low Income *Last change*	10	WMA	$0.00140 *2/1/18*	$0.01086 *2/1/18*	$0.00472 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00252 *2/1/18*	($0.00013) *2/1/18*	$0.00023 *2/1/18*	$0.02294 *2/1/18*
23 Optional Water Heating *Last change*	36	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
24 Optional Church *Last change*	37	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
G-0 Small General Service *Last change*	38	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
T-0 Small General Service TOU *Last change*	39	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
G-2 Primary General Service *Last change*	40	WMA	$0.00063 *2/1/18*	$0.00638 *2/1/18*	$0.00277 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00148 *2/1/18*	($0.00008) *2/1/18*	$0.00013 *2/1/18*	$0.01464 *2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

WESTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
T-4 Primary General Service TOU *Last change*	41	WMA	$0.00063 *2/1/18*	$0.00638 *2/1/18*	$0.00277 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00148 *2/1/18*	($0.00008) *2/1/18*	$0.00013 *2/1/18*	$0.01464 *2/1/18*
T-2 Large Primary Service TOU *Last Change*	42	WMA	$0.00052 *2/1/18*	$0.00471 *2/1/18*	$0.00205 *2/1/18*	$0.00001 *2/1/18*	$0.00331 *1/1/18*	$0.00109 *2/1/18*	($0.00006) *2/1/18*	$0.00010 *2/1/18*	$0.01173 *2/1/18*
T-5 Extra Large Primary Service TOU *Last Change*	43	WMA	$0.00032 *2/1/18*	$0.00253 *2/1/18*	$0.00110 *2/1/18*	$0.00001 *2/1/18*	$0.00331 *1/1/18*	$0.00059 *2/1/18*	($0.00003) *2/1/18*	$0.00005 *2/1/18*	$0.00788 *2/1/18*
S-1 Street and Security Lighting *Last Change*	44	WMA	$0.00388 *2/1/18*	$0.00657 *2/1/18*	$0.00286 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00153 *2/1/18*	($0.00008) *2/1/18*	$0.00014 *2/1/18*	$0.01823 *2/1/18*
S-2 Street and Security Lighting - Customer Owned *Last Change*	45	WMA	$0.00388 *2/1/18*	$0.00657 *2/1/18*	$0.00286 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00153 *2/1/18*	($0.00008) *2/1/18*	$0.00014 *2/1/18*	$0.01823 *2/1/18*

PART C - BASIC SERVICE *
All Rates are in $/kWh across all hours and usage levels

WESTERN MASSACHUSETTS																
Sector	Class	Type	Zone	01-Jan-18	01-Feb-18	01-Mar-18	01-Apr-18	01-May-18	01-Jun-18	01-Jul-18	01-Aug-18	01-Sep-18	01-Oct-18	01-Nov-18	01-Dec-18	*Last change*
Residential	R-1, R-2, R-3, R-4	Fixed	ALL	$0.10486	$0.10503	$0.10503	$0.10503	$0.10503	$0.10503	$0.10003	$0.10003	$0.10003	$0.10003	$0.10003	$0.10003	*7/1/18*
		Variable	ALL	$0.12646	$0.12637	$0.10048	$0.08882	$0.08582	$0.09165	$0.09436	$0.09346	$0.09616	$0.10129	$0.10032	$0.11404	*7/1/18*
Small C&I	All classes otherwise not listed here	Fixed	ALL	$0.11404	$0.11421	$0.11421	$0.11421	$0.11421	$0.11421	$0.10859	$0.10859	$0.10859	$0.10859	$0.10859	$0.10859	*7/1/18*
		Variable	ALL	$0.13498	$0.13831	$0.11040	$0.09891	$0.09493	$0.09724	$0.10335	$0.10212	$0.10361	$0.10784	$0.10911	$0.12428	*7/1/18*
Large C&I	G-2, T-4, T-2, T-5	Fixed	WCMA	$0.12241	$0.12258	$0.12258	$0.09091	$0.09091	$0.09091	$0.09857	$0.09857	$0.09857				*7/1/18*
		Variable	WCMA	$0.12988	$0.13145	$0.10499	$0.09695	$0.08871	$0.08733	$0.09945	$0.09791	$0.09821				*7/1/18*
St. Lighting	S-1, S-2	Fixed	ALL	$0.07359	$0.07376	$0.07376	$0.07376	$0.07376	$0.07376	$0.06267	$0.06267	$0.06267	$0.06267	$0.06267	$0.06267	*7/1/18*
		Variable	ALL	$0.09779	$0.09621	$0.07107	$0.05480	$0.05074	$0.05093	$0.05736	$0.05584	$0.05435	$0.05816	$0.06138	$0.08132	*7/1/18*

* Includes the Basic Service Bad Debt Cost of $0.00156

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

WESTERN MASSACHUSETTS														
										Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
R-1 Residential	7	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.04372	$0.02694	$0.07066	$0.00075	($0.00171)	$0.02797	$0.00250	$0.01402	$0.01652	$0.00050	$0.11469
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
R-2 Residential Assistance	8	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.04372	$0.02694	$0.07066	$0.00075	($0.00171)	$0.02797	$0.00250	$0.00065	$0.00315	$0.00050	$0.10132
			Discount	36%										
Last change				*2/1/18*	2/1/18	2/1/18	2/1/18	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
R-3 Residential Space Heating	9	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.03835	$0.02294	$0.06129	$0.00064	($0.00171)	$0.02820	$0.00250	$0.01402	$0.01652	$0.00050	$0.10544
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
R-4 Residential Space Heating Assistance	10	WMA	Customer	$7.00		$7.00								$7.00
			Energy (kWh)	$0.03835	$0.02294	$0.06129	$0.00064	($0.00171)	$0.02820	$0.00250	$0.00065	$0.00315	$0.00050	$0.09207
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
23 Optional Water Heating	36	WMA	Customer	$17.00		$17.00								$17.00
			Energy (kWh)	$0.02399	$0.02152	$0.04551	$0.00057	($0.00171)	$0.02121	$0.00250	$0.00972	$0.01222	$0.00050	$0.07830
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
24 Optional Church	37	WMA	Customer	$65.00		$65.00								$65.00
			Demand (>2 kW)	$3.84		$3.84			$3.52					$7.36
			Energy (kWh)	$0.00490	$0.02152	$0.02642	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.03800
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
G-0 Small General Service	38	WMA	Customer (without meter)	$15.00		$15.00								$15.00
			Customer (with meter)	$30.00		$30.00								$30.00
			Demand (>2 kW)	$9.03		$9.03			$7.52					$16.55
			Energy (kWh)	$0.00177	$0.02152	$0.02329	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.03487
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
T-0 Small General Service TOU	39	WMA	Customer	$30.00		$30.00								$30.00
			Demand (>2 kW)	$9.10		$9.10			$10.13					$19.23
			Peak kWh	$0.00285	$0.02152	$0.02437	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.03595
			Off Peak kWh	$0.00076	$0.02152	$0.02228	$0.00057	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.03386
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*

PART A - TOTAL DELIVERY RATES
(1) Reconciling Rates = Sum of Part B Rates

WESTERN MASSACHUSETTS														
										Energy Efficiency Charge (EEC)				
Schedule	MDPU No.	Service Area	Rate Component	Base Distribution	Reconciling Rate Adjust (1)	Total Distribution	Revenue Decoupling	Transition	Transmission	System Benefits	Recon. Factor	Total EEC	Renewable Energy	Total Delivery
G-2 Primary General Service	40	WMA	Customer	$353.00		$353.00								$353.00
			Demand (<=50 kW)	$1.61		$1.61			$7.00					$8.61
			Demand (>50 kW)	$7.57		$7.57			$7.00					$14.57
			Energy (kWh)	$0.00169	$0.01464	$0.01633	$0.00035	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.02769
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
T-4 Primary General Service TOU	41	WMA	Customer	$353.00		$353.00								$353.00
			Demand (<=50 kW)	$1.61		$1.61			$7.85					$9.46
			Demand (>50 kW)	$7.58		$7.58			$7.85					$15.43
			Peak kWh	$0.00255	$0.01464	$0.01719	$0.00035	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.02855
			Off Peak kWh	$0.00072	$0.01464	$0.01536	$0.00035	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.02672
Last change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
T-2 Large Primary Service TOU	42	WMA	Customer (350<= kW < 1000 kW)	$760.00		$760.00								$760.00
			Customer (1000<= kW < 1500 kW)	$1,625.00		$1,625.00								$1,625.00
			Customer (1500<= kW < 2500 kW)	$2,700.00		$2,700.00								$2,700.00
			Demand (kW)	$6.22		$6.22			$9.02					$15.24
			Peak kWh	$0.00253	$0.01173	$0.01426	$0.00026	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.02553
			Off Peak kWh	$0.00074	$0.01173	$0.01247	$0.00026	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.02374
Last Change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
T-5 Extra Large Primary Service TOU	43	WMA	Customer	$3,800.00		$3,800.00								$3,800.00
			On Peak Demand	$4.44		$4.44			$7.55					$11.99
			Coincident Peak Demand						$11.87					$11.87
			Peak kWh	$0.00254	$0.00788	$0.01042	$0.00014	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.02157
			Off Peak kWh	$0.00075	$0.00788	$0.00863	$0.00014	($0.00171)	$0.00000	$0.00250	$0.00972	$0.01222	$0.00050	$0.01978
Last Change				*2/1/18*	*2/1/18*	*2/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
S-1 Street and Security Lighting	44	WMA	Fixture Charge	Per Rate Schedule		Per Rate Schedule								Per Rate Schedule
			kWh		$0.01823		$0.00037	($0.00171)	$0.01493	$0.00250	$0.00972	$0.01222	$0.00050	
Last Change				*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*
S-2 Street and Security Lighting - Customer Owned	45	WMA	Per Watt	$0.01141		$0.01141								$0.01141
			kWh		$0.01823	$0.01823	$0.00037	($0.00171)	$0.01493	$0.00250	$0.00972	$0.01222	$0.00050	$0.04454
Last Change				*7/1/18*	*2/1/18*	*7/1/18*	*2/1/18*	*1/1/18*	*1/1/18*	*3/1/98*	*7/1/18*	*7/1/18*	*1/1/03*	*7/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

WESTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
R-1 Residential *Last change*	7	WMA	$0.00143 *2/1/18*	$0.01323 *2/1/18*	$0.00575 *2/1/18*	$0.00004 *2/1/18*	$0.00331 *1/1/18*	$0.00307 *2/1/18*	($0.00016) *2/1/18*	$0.00027 *2/1/18*	$0.02694 *2/1/18*
R-2 Residential Low Income *Last change*	8	WMA	$0.00143 *2/1/18*	$0.01323 *2/1/18*	$0.00575 *2/1/18*	$0.00004 *2/1/18*	$0.00331 *1/1/18*	$0.00307 *2/1/18*	($0.00016) *2/1/18*	$0.00027 *2/1/18*	$0.02694 *2/1/18*
R-3 Residential Space Heating *Last change*	9	WMA	$0.00140 *2/1/18*	$0.01086 *2/1/18*	$0.00472 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00252 *2/1/18*	($0.00013) *2/1/18*	$0.00023 *2/1/18*	$0.02294 *2/1/18*
R-4 Residential Space Heating Low Income *Last change*	10	WMA	$0.00140 *2/1/18*	$0.01086 *2/1/18*	$0.00472 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00252 *2/1/18*	($0.00013) *2/1/18*	$0.00023 *2/1/18*	$0.02294 *2/1/18*
23 Optional Water Heating *Last change*	36	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
24 Optional Church *Last change*	37	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
G-0 Small General Service *Last change*	38	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
T-0 Small General Service TOU *Last change*	39	WMA	$0.00111 *2/1/18*	$0.01019 *2/1/18*	$0.00443 *2/1/18*	$0.00003 *2/1/18*	$0.00331 *1/1/18*	$0.00237 *2/1/18*	($0.00013) *2/1/18*	$0.00021 *2/1/18*	$0.02152 *2/1/18*
G-2 Primary General Service *Last change*	40	WMA	$0.00063 *2/1/18*	$0.00638 *2/1/18*	$0.00277 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00148 *2/1/18*	($0.00008) *2/1/18*	$0.00013 *2/1/18*	$0.01464 *2/1/18*

PART B - RECONCILING RATES
(1) All Rates are in $/kWh across all hours and usage levels; totals appear in Part A

WESTERN MASSACHUSETTS											
Schedule	MDPU No.	Service Area	Pension Adjustment Factor (PAF)	Residential Assistance Adjustment Factor (RAAF)	Net Metering Recovery Surcharge (NMRS)	Attorney General Consulting Expense (AGCE)	Long Term Renewable Contract Adjustment (LTRCA)	Storm Cost Recovery Adjustment Factor (SCRAF)	Solar Program Cost Adjustment Factor (SPCA)	Basic Service Cost True Up Factor (BSTF)	Total
T-4 Primary General Service TOU *Last change*	41	WMA	$0.00063 *2/1/18*	$0.00638 *2/1/18*	$0.00277 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00148 *2/1/18*	($0.00008) *2/1/18*	$0.00013 *2/1/18*	$0.01464 *2/1/18*
T-2 Large Primary Service TOU *Last Change*	42	WMA	$0.00052 *2/1/18*	$0.00471 *2/1/18*	$0.00205 *2/1/18*	$0.00001 *2/1/18*	$0.00331 *1/1/18*	$0.00109 *2/1/18*	($0.00006) *2/1/18*	$0.00010 *2/1/18*	$0.01173 *2/1/18*
T-5 Extra Large Primary Service TOU *Last Change*	43	WMA	$0.00032 *2/1/18*	$0.00253 *2/1/18*	$0.00110 *2/1/18*	$0.00001 *2/1/18*	$0.00331 *1/1/18*	$0.00059 *2/1/18*	($0.00003) *2/1/18*	$0.00005 *2/1/18*	$0.00788 *2/1/18*
S-1 Street and Security Lighting *Last Change*	44	WMA	$0.00388 *2/1/18*	$0.00657 *2/1/18*	$0.00286 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00153 *2/1/18*	($0.00008) *2/1/18*	$0.00014 *2/1/18*	$0.01823 *2/1/18*
S-2 Street and Security Lighting - Customer Owned *Last Change*	45	WMA	$0.00388 *2/1/18*	$0.00657 *2/1/18*	$0.00286 *2/1/18*	$0.00002 *2/1/18*	$0.00331 *1/1/18*	$0.00153 *2/1/18*	($0.00008) *2/1/18*	$0.00014 *2/1/18*	$0.01823 *2/1/18*

PART C - BASIC SERVICE *
All Rates are in $/kWh across all hours and usage levels

WESTERN MASSACHUSETTS																
Sector	Class	Type	Zone	01-Jan-18	01-Feb-18	01-Mar-18	01-Apr-18	01-May-18	01-Jun-18	01-Jul-18	01-Aug-18	01-Sep-18	01-Oct-18	01-Nov-18	01-Dec-18	*Last change*
Residential	R-1, R-2, R-3, R-4	Fixed	ALL	$0.10486	$0.10503	$0.10503	$0.10503	$0.10503	$0.10503	$0.10003	$0.10003	$0.10003	$0.10003	$0.10003	$0.10003	*7/1/18*
		Variable	ALL	$0.12646	$0.12637	$0.10048	$0.08882	$0.08582	$0.09165	$0.09436	$0.09346	$0.09616	$0.10129	$0.10032	$0.11404	*7/1/18*
Small C&I	All classes otherwise not listed here	Fixed	ALL	$0.11404	$0.11421	$0.11421	$0.11421	$0.11421	$0.11421	$0.10859	$0.10859	$0.10859	$0.10859	$0.10859	$0.10859	*7/1/18*
		Variable	ALL	$0.13498	$0.13831	$0.11040	$0.09891	$0.09493	$0.09724	$0.10335	$0.10212	$0.10361	$0.10784	$0.10911	$0.12428	*7/1/18*
Large C&I	G-2, T-4, T-2, T-5	Fixed	WCMA	$0.12241	$0.12258	$0.12258	$0.09091	$0.09091	$0.09091	$0.09857	$0.09857	$0.09857	$0.11387	$0.11387	$0.11387	*10/1/18*
		Variable	WCMA	$0.12988	$0.13145	$0.10499	$0.09695	$0.08871	$0.08733	$0.09945	$0.09791	$0.09821	$0.10336	$0.10384	$0.12985	*10/1/18*
St. Lighting	S-1, S-2	Fixed	ALL	$0.07359	$0.07376	$0.07376	$0.07376	$0.07376	$0.07376	$0.06267	$0.06267	$0.06267	$0.06267	$0.06267	$0.06267	*7/1/18*
		Variable	ALL	$0.09779	$0.09621	$0.07107	$0.05480	$0.05074	$0.05093	$0.05736	$0.05584	$0.05435	$0.05816	$0.06138	$0.08132	*7/1/18*

* Includes the Basic Service Bad Debt Cost of $0.00156

Commonwealth of Massachusetts
Department of Public Utilities
One South Street
Boston, MA 02110

STATEMENT OF OPERATING REVENUES

YEAR 2018

Name of Company	**NSTAR Electric Company ***
D/B/A	Eversource Energy
Address	800 Boylston Street
	Boston, MA 02199-8003

		Location on Annual Return
Massachusetts Operating Revenues (Intrastate)	$2,898,047,333	FERC Form 1, page 300, line 10, column b
Other Revenues (Outside Massachusetts)	$0	
Total Revenues	$2,898,047,333	

I hereby certify under the penalties of perjury that the foregoing statement is true to the best of my knowledge and belief.

Signature	
Name	Jay S. Buth
Title	Vice President, Controller and Chief Accounting Officer

The purpose of this statement is to provide the Department of Public Utilities with the amount of intrastate operating revenues for the annual assessment made pursuant to G.L. c. 25, § 18.

If invoices or correspondence are to be addressed to a particular individual or department of the Company, please provide the name, title, and address below.

*On December 31, 2017, Western Massachusetts Electric Company was merged with and into NSTAR Electric Company. This report reflects the consolidated NSTAR Electric Company and former Western Massachusetts Electric Company.

Name	Carla J. Dacey
Title	Manager, Revenue and Regulatory Accounting
Address	247 Station Drive, Westwood, MA 02090