

215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpc.com (web site)



May 5, 2017

Darrell Nitschke
Executive Secretary/Director of Administration
North Dakota Public Service Commission
State Capitol - 600 East Boulevard
Bismarck, ND 58505-0480

**RE: Otter Tail Power Company's Annual Report – FERC Form 1
Supplemental Filing**

Dear Mr. Nitschke:

On May 4, 2017, Otter Tail Power Company submitted their 2016 Annual Report for North Dakota. Due to technical difficulties at FERC, Otter Tail's 2016 FERC Form 1 was not filed at this time. Enclosed please find an official PDF copy of the 2016 FERC Form 1.

If you have questions on the information provided, don't hesitate to contact me at (218) 739-8279 or stommerdahl@otpc.com.

Sincerely,

/s/ STUART TOMMERDAHL
Stuart Tommerdahl
Manager, Regulatory Administration

kaw
Enclosures
By electronic service and First Class mail

THIS FILING IS

Item 1: 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)

Otter Tail Power Company

Year/Period of Report

End of 2016/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.)

<u>Reference Schedules</u>	<u>Pages</u>
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 1,144 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 150 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 filed..."

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).

REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Otter Tail Power Company		02 Year/Period of Report End of <u>2016/Q4</u>
03 Previous Name and Date of Change <i>(if name changed during year)</i> / /		
04 Address of Principal Office at End of Period <i>(Street, City, State, Zip Code)</i> 215 South Cascade Street, PO Box 496, Fergus Falls, MN 56538-0496		
05 Name of Contact Person Jeff Legge		06 Title of Contact Person Controller, Utility
07 Address of Contact Person <i>(Street, City, State, Zip Code)</i> PO Box 496, Fergus Falls, MN 56538-0496		
08 Telephone of Contact Person, <i>Including Area Code</i> (218) 739-8291	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report <i>(Mo, Da, Yr)</i> 12/31/2016

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 George Bell	03 Signature George Bell	04 Date Signed <i>(Mo, Da, Yr)</i> 04/04/2017
02 Title Chief Financial Officer		

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.

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	Not applicable
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	Not applicable
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	
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	

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	
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	
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 Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of 2016/Q4
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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	
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
- No annual report to stockholders is prepared

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of <u>2016/Q4</u>
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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.

Jeff Legge, Controller-Utility
215 South Cascade Street, PO Box 496
Fergus Falls, MN 56538-0496

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.

Minnesota - July 5, 1907

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.

Not Applicable

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

Minnesota - Electric
North Dakota - Electric
South Dakota - Electric

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) No

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report <i>(Mo, Da, Yr)</i> 12/31/2016	Year/Period of Report End of <u>2016/Q4</u>
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CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent 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 beneficiaries for whom trust was maintained, and purpose of the trust.

Otter Tail Corporation, a registered holding company, owns all of the common stock of the respondent.

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	Not applicable.			
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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	Chief Executive Officer, Utility * **	Charles S. MacFarlane	309,750
2			
3	President, Utility	Timothy J. Rogelstad	350,000
4			
5	Vice President, Customer Service	Mark H. Helland	188,515
6			
7	Vice President, Administration	Thomas R. Brause	225,207
8			
9	Chief Financial Officer	George D. Bell	207,564
10			
11	Vice President, Energy Supply	Jan P. Rudolf	191,315
12			
13	General Counsel & Secretary	Jennifer O. Smestad	183,575
14			
15	Vice President, Asset Management	JoAnn M. Thompson	166,113
16			
17	Vice President, Public Relations	Cris M. Oehler	163,567
18			
19	Vice President, Planning and Strategy	Bradley E. Tollerson	184,426
20			
21	Vice President, Information Technology * ** [3]	Don L. Redden	93,500
22			
23	Treasurer * **	Kevin G. Moug	262,910
24			
25	Assistant Secretary * **	George A. Koeck	236,400
26			
27	Assistant Treasurer * ** [1]	Suzanne Allen	36,601
28			
29	Assistant Treasurer * ** [2]	Brian Carlson	111,395
30			
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36			
37	[1] Removed effective 09/02/2016.		
38	[2] Effective 09/02/2016.		
39	[3] Effective 12/01/2016.		
40			
41	* This individual is an employee of		
42	Otter Tail Corporation.		
43			
44	** Portion of salary allocated to the Utility.		

Name of Respondent
Otter Tail Power Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2016

Year/Period of Report
End of 2016/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		
2	George A. Koeck, Director, Assistant Secretary	Fargo, North Dakota
3		
4	Charles S. MacFarlane, Director, and CEO, Utility	Fergus Falls, Minnesota
5		
6	Kevin Moug, Director, Treasurer	Fargo, North Dakota
7		
8	Timothy J. Rogelstad, Director, President, Utility	Fergus Falls, Minnesota
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10	John Abbott, Director	Fargo, North Dakota
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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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	MISO FERC Electric Tariff Original Vol. No. 1	ER98-1438-000
2	MISO FERC Electric Tariff 2nd Revised Vol. No. 1	ER04-895-000
3	MISO FERC Electric Tariff 2nd Revised Vol. No. 1	ER05-122-000
4	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER04-458-008
5	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER06-18-000
6	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER06-159-000
7	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER09-91-000
8	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER09-1657-000
9	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER09-1779-000
10	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-183
11	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-686
12	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-1492-000
13	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-1791
14	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER10-1997-000;001
15	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER11-28-000;01
16	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER11-3279-000
17	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER11-3704-000
18	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-297-000
19	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-312-000
20	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-334-000
21	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-450-000
22	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-715-000;002
23	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-1667-000
24	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER13-263-001
25	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER13-674-000;002
26	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER13-1169-000
27	MISO FERC Electric Tariff	ER13-1169-001
28	MISO FERC Electric Tariff	ER12-480-006;007
29	MISO FERC Electric Tariff	ER13-2379-000;003;004
30	MISO FERC Electric Tariff	ER14-260-000
31	MISO FERC Electric Tariff	ER14-261-000
32	MISO FERC Electric Tariff	ER14-421-000;001
33	MISO FERC Electric Tariff	ER15-358
34	MISO FERC Electric Tariff	ER15-1490
35	MISO FERC Electric Tariff	ER16-1313
36	MISO FERC Electric Tariff	ER16-1534
37	MISO FERC Electric Tariff	ER16-392
38	MISO FERC Electric Tariff	ER16-197
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Name of Respondent
Otter Tail Power Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2016

Year/Period of Report
End of 2016/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)?

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	20150313-5220	03/13/2015	ER15-1276	Attachment O Annual Informationa	MISO FERC Electric Tariff
2	20160315-5126	03/15/2016	ER16-1196	Attachment O Annual Informationa	MISO FERC Electric Tariff
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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
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Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 12/31/2016	Year/Period of Report End of <u>2016/Q4</u>
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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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. None.
2. None.
3. The MPUC approved the purchase of 3 miles of de-energized transmission line on October 19, 2016 in Docket No. E017/PA-16-441.
4. None.
5. None.
6. See Footnote 8 in Notes to Financial Statements. Minnesota Public Utilities Commission authorization given under Docket No. E-017/S-16-367 dated August 2, 2016.
7. None.
8. The average annual increase for full-time nonunion employees was 3.0% effective April 1, 2016. Wages for Local Union 1570 were increased by 3.0% effective September 1, 2016. Wages for Local Unions 949, 524, 239 and 203 were increased by 3.0% effective November 1, 2016.
9. See Footnote 7 in Notes to Financial Statements.
10. Otter Tail Power Company is a subsidiary of Otter Tail Corporation.
11. (Reserved.)
12. None.
13. On September 2, 2016, Suzanne Allen was removed as Assistant Treasurer and Brian Carlson was elected to Assistant Treasurer. On December 1, 2016, Don L. Redden was elected as Vice President, Information Technology.
14. Not applicable.

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	1,860,356,979	1,820,763,015
3	Construction Work in Progress (107)	200-201	149,997,025	64,117,181
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		2,010,354,004	1,884,880,196
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	703,060,660	666,949,303
6	Net Utility Plant (Enter Total of line 4 less 5)		1,307,293,344	1,217,930,893
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)		1,307,293,344	1,217,930,893
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		879,911	664,511
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
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)		76,551	102,343
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		1,095,534	903,538
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)		2,051,996	1,670,392
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		9,800	11,300
36	Special Deposits (132-134)		3,208,360	1,847,407
37	Working Fund (135)		12,446	16,940
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	50,000
40	Customer Accounts Receivable (142)		20,792,118	19,172,775
41	Other Accounts Receivable (143)		5,541,055	8,477,335
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		884,718	855,596
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		10,447	11,175
45	Fuel Stock (151)	227	9,830,796	12,309,141
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	18,822,509	19,118,093
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	31,385	59,417

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	0	0
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)		916,587	932,933
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		21,878,276	16,035,137
62	Miscellaneous Current and Accrued Assets (174)		-5,684	5,698
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)		80,163,377	77,191,755
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		2,619,437	2,850,815
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	3,507,827	4,304,770
72	Other Regulatory Assets (182.3)	232	146,545,983	140,415,631
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
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)		0	-11,351
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	0	0
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)		1,539,120	1,890,097
82	Accumulated Deferred Income Taxes (190)	234	127,522,091	138,860,665
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		281,734,458	288,310,627
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,671,243,175	1,585,103,667

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

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

Per its FERC-approved tariff, the Company uses a 13-month average of allowable prepaid expenses for rate-making purposes, illustrated as follows for the current year:

December 31, 2015	932,933
January 31, 2016	2,296,924
February 29, 2016	2,315,344
March 31, 2016	1,857,103
April 30, 2016	3,540,755
May 31, 2016	3,210,378
June 30, 2016	2,846,255
July 31, 2016	2,517,480
August 31, 2016	2,069,754
September 30, 2016	1,958,009
October 31, 2016	1,554,968
November 30, 2016	1,354,052
December 31, 2016	916,587
 13-month average for rate-making	 2,105,426

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	500	500
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	376,988,966	339,988,966
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	169,810,191	158,534,255
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
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)	-1,641,899	-1,676,110
16	Total Proprietary Capital (lines 2 through 15)		545,157,758	496,847,611
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	445,000,000	445,000,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	0
24	Total Long-Term Debt (lines 18 through 23)		445,000,000	445,000,000
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		603,589	577,000
29	Accumulated Provision for Pensions and Benefits (228.3)		141,072,156	135,021,435
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		3,624,425	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		8,341,004	8,083,769
35	Total Other Noncurrent Liabilities (lines 26 through 34)		153,641,174	143,682,204
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		42,883,278	21,005,840
38	Accounts Payable (232)		56,764,068	53,590,862
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		1,571,640	1,927,904
41	Customer Deposits (235)		1,074,025	1,090,716
42	Taxes Accrued (236)	262-263	14,801,360	13,310,233
43	Interest Accrued (237)		6,928,094	6,846,044
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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 column in 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	420,778,717	399,535,911		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	241,798,227	231,850,778		
5	Maintenance Expenses (402)	320-323	27,423,931	28,176,032		
6	Depreciation Expense (403)	336-337	50,100,398	41,441,421		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	121,347	146,067		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	1,830,060	1,496,906		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337		44,939		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		948,563	740,192		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		682,645			
13	(Less) Regulatory Credits (407.4)		2,430,499	778,134		
14	Taxes Other Than Income Taxes (408.1)	262-263	14,258,363	13,504,765		
15	Income Taxes - Federal (409.1)	262-263	-173,056	-1,845,914		
16	- Other (409.1)	262-263	584,926	-394,453		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	3,201,434	24,176,441		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	-12,142,002	6,780,347		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,656,731	-1,877,994		
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)		17	29		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		360,169	335,743		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		349,191,762	330,236,413		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		71,586,955	69,299,498		

Name of Respondent
Otter Tail Power Company

This Report Is:
(1) An Original
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Date of Report
(Mo, Da, Yr)
12/31/2016

Year/Period of Report
End of 2016/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)	
420,778,717	399,535,911					2
						3
241,798,227	231,850,778					4
27,423,931	28,176,032					5
50,100,398	41,441,421					6
121,347	146,067					7
1,830,060	1,496,906					8
	44,939					9
948,563	740,192					10
						11
682,645						12
2,430,499	778,134					13
14,258,363	13,504,765					14
-173,056	-1,845,914					15
584,926	-394,453					16
3,201,434	24,176,441					17
-12,142,002	6,780,347					18
-1,656,731	-1,877,994					19
						20
						21
17	29					22
						23
360,169	335,743					24
349,191,762	330,236,413					25
71,586,955	69,299,498					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
			Current Year (c)	Previous Year (d)		
27	Net Utility Operating Income (Carried forward from page 114)		71,586,955	69,299,498		
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)		640,333	777,666		
34	(Less) Expenses of Nonutility Operations (417.1)		429,796	534,579		
35	Nonoperating Rental Income (418)		56,167	56,081		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		166,189	208,005		
38	Allowance for Other Funds Used During Construction (419.1)		856,829	1,302,804		
39	Miscellaneous Nonoperating Income (421)		5,315,234	5,086,141		
40	Gain on Disposition of Property (421.1)			9,258		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		6,604,956	6,905,376		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		472,464	375,508		
46	Life Insurance (426.2)					
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		225,385	187,404		
49	Other Deductions (426.5)		320,964	104,201		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,018,813	667,113		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	7,848	7,404		
53	Income Taxes-Federal (409.2)	262-263	116,284	2,077,088		
54	Income Taxes-Other (409.2)	262-263	19,090	394,461		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	2,318,646	633,974		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	186,424	316,413		
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)		2,275,444	2,796,514		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		3,310,699	3,441,749		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		23,931,900	23,931,900		
63	Amort. of Debt Disc. and Expense (428)		396,195	388,084		
64	Amortization of Loss on Reaquired Debt (428.1)		350,978	350,978		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		884,688	423,148		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		494,942	723,318		
70	Net Interest Charges (Total of lines 62 thru 69)		25,068,819	24,370,792		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		49,828,835	48,370,455		
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)		49,828,835	48,370,455		

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		157,957,063	146,601,836
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		49,828,835	48,370,455
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess hydro licensing amortization		-44,960	(64,511)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-44,960	(64,511)
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-38,552,899	(36,950,717)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-38,552,899	(36,950,717)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		169,188,039	157,957,063
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39	Amortization reserve, federal (Account 215.1)		622,152	577,192
40				

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)		622,152	577,192
	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)		622,152	577,192
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		169,810,191	158,534,255
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

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)	49,828,835	48,370,455
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	50,221,745	41,587,487
5	Amortization	2,226,256	1,929,930
6	Vehicle Depreciation allocated to various operating accounts	1,817,963	1,807,939
7			
8	Deferred Income Taxes (Net)	17,350,056	18,094,269
9	Investment Tax Credit Adjustment (Net)	-1,656,731	-1,877,994
10	Net (Increase) Decrease in Receivables	2,446,892	-1,008,629
11	Net (Increase) Decrease in Inventory	2,773,929	-3,379,682
12	Net (Increase) Decrease in Allowances Inventory	28,032	-59,417
13	Net Increase (Decrease) in Payables and Accrued Expenses	8,739,040	-19,326,882
14	Net (Increase) Decrease in Other Regulatory Assets	-5,333,409	7,065,924
15	Net Increase (Decrease) in Other Regulatory Liabilities	1,351,603	37,172
16	(Less) Allowance for Other Funds Used During Construction	856,829	1,302,804
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other: (in cease) decrease in noncurrent assets and deferred debits	173,422	509,677
19	Other: Increase(decrease) in noncurrent liabilities & deferred credits	6,041,165	8,204,906
20	Other: (Increase) decrease in other current assets	-5,765,411	2,841,793
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	129,386,558	103,494,144
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-143,232,219	-136,779,717
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-215,400	-235,000
30	(Less) Allowance for Other Funds Used During Construction	-856,829	-1,302,804
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-142,590,790	-135,711,913
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		
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)		
45	Proceeds from Sales of Investment Securities (a)		

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	-1,100,105	5,694,409
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	-4,482,543	-5,897,233
53	Other: (Increase) decrease in funds on deposit with trustee	-1,360,953	902,524
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-149,534,391	-135,012,213
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
62	Preferred Stock		
63	Common Stock		
64	Other: debt issuance expense	-164,818	-159,367
65			
66	Net Increase in Short-Term Debt (c)	21,877,438	21,005,840
67	Other: change in checks written in excess of cash	-17,882	3,745,444
68	Other: proceeds from capital infusions	37,000,000	43,727,575
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	58,694,738	68,319,492
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-38,552,899	-36,950,717
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	20,141,839	31,368,775
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-5,994	-149,294
87			
88	Cash and Cash Equivalents at Beginning of Period	28,240	177,534
89			
90	Cash and Cash Equivalents at End of period	22,246	28,240

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 120 Line No.: 5 Column: a

Amortization of intangible plant, plant acquisition adjustments and deferred costs, and debt discount and expense.

Schedule Page: 120 Line No.: 18 Column: a

Changes in miscellaneous deferred debits.

Schedule Page: 120 Line No.: 19 Column: a

Includes changes in: other investments, other special funds, clearing accounts, miscellaneous deferred credits, and unamortized loss on reacquired debt.

Schedule Page: 120 Line No.: 20 Column: a

Includes changes in: notes receivable, prepayments, interest and dividends receivable, accrued utility revenues, miscellaneous current and accrued assets.

Schedule Page: 120 Line No.: 53 Column: a

Change in special funds on deposit with fiscal agent.

Schedule Page: 120 Line No.: 64 Column: a

Debt issuance expense.

Schedule Page: 120 Line No.: 67 Column: a

Change in checks written in excess of cash.

Schedule Page: 120 Line No.: 68 Column: a

Proceeds from capital infusions from parent company.

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 12/31/2016	Year/Period of Report End of <u>2016/Q4</u>
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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 Commission 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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Reconciliation of Cash and Cash Equivalents (Lines 88 and 90 on Page 121)

With Balance Sheet Accounts (Page 110):

Account 136 – Temporary Cash Investment (Line 38, Page 110), contains amounts which are considered cash equivalents.

	<u>2016</u>		<u>2015</u>
Cash Equivalents	\$ 0		\$ 0
Reconciliation	<u>2015</u>		<u>2015</u>
Cash – Account 131 (Line 35, Page 110)	\$ 9,800		\$ 11,300
Working Fund – Account 135 (Line 37, Page 110)	12,446		16,940
Cash Equivalent – Account 136 (Above)	<u>0</u>		<u>0</u>
	\$ 22,246		\$ 28,240

Otter Tail Power Company

Notes to Financial Statements

For the years ended December 31, 2016 and 2015

1. Summary of Significant Accounting Policies

Organization and Operations

Otter Tail Power Company (OTP) was incorporated in 1907 under the laws of the State of Minnesota and is a wholly owned subsidiary of Otter Tail Corporation.

On July 1, 2009, Otter Tail Corporation completed a holding company reorganization whereby OTP, which had previously been operated as a division of Otter Tail Corporation, became a wholly owned subsidiary of the new parent holding company named Otter Tail Corporation. The new parent holding company was incorporated in June 2009 under the laws of the State of Minnesota in connection with the holding company reorganization.

OTP includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota. In addition, OTP is a participant in the Midcontinent Independent System Operator, Inc. (MISO) markets.

OTP provides electricity to more than 130,000 customers in a service area encompassing 70,000 square miles of western Minnesota, eastern North Dakota and northeastern South Dakota. The territory served by OTP is predominantly agricultural. The aggregate population of OTP's retail electric service area is approximately 230,000. In this service area of 422 communities and adjacent rural areas and farms, approximately 126,000 people live in communities having a population of more than 1,000, according to the 2010 census. The only communities served which have a population in excess of 10,000 are Jamestown, North Dakota (15,427); Bemidji, Minnesota (13,431); and Fergus Falls, Minnesota (13,138). As of December 31, 2016 OTP served 131,546 customers. Although there are relatively few large customers, sales to commercial and industrial customers are significant.

Related Party

Included in the amounts presented in the balance sheet and income statement are the following related party balances:

<i>(in thousands)</i>	2016	2015
Accounts Receivable	\$ 10	\$ 11
Accounts Payable	1,572	1,928
Operating Revenues	34	92
Other Operation and Maintenance Expenses	9,582	10,868

The related party transactions predominately relate to the allocation of corporate overhead expenses and corporate aircraft usage to OTP and rent charged to Otter Tail Corporation for its use of office space in Fergus Falls. The corporate overhead expenses include such items as labor, professional services, office rent, subscriptions, information technology and general office expenses incurred by Otter Tail Corporation.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

These expenses are allocated to OTP based on the type of expenditure, using an allocation methodology as defined in the Otter Tail Corporation's Corporate Cost Allocation Manual.

Regulation and Accounting Standards Codification (ASC) Topic 980 (ASC 980)

OTP, a regulated electric utility company, accounts for the financial effects of regulation in accordance with the requirements of Financial Accounting Standards Board (FASB) ASC 980, *Regulated Operations*. This standard allows for the recording of a regulatory asset or liability for costs and revenues that will be collected or refunded through the ratemaking process in the future. In accordance with regulatory treatment, OTP defers utility debt redemption premiums and amortizes such costs over the original life of the reacquired bonds. See note 3 for further discussion.

OTP is subject to various state and federal agency regulations. The accounting policies followed by this business are subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC).

Financial Statement Presentation and Basis of Accounting

The financial statements are presented on the basis of the accounting requirements of FERC as set forth in its applicable Uniform System of Accounts and this report differs from GAAP. The significant differences consist of the following:

- Comparative statements of net income per share are not presented.
- The accumulated reserve for estimated removal costs is included in the accumulated provision for depreciation for FERC reporting. For GAAP reporting it is reported as a regulatory liability.
- Current and long-term debt is classified in the balance sheet as all long-term debt in accordance with regulatory treatment, while GAAP presentation reflects current and long-term debt separately.
- Accumulated deferred tax assets and liabilities are classified in the balance sheet as gross deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred asset or liability.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP, while FERC classifies all regulatory assets and liabilities as noncurrent deferred debits and credits, respectively.
- Certain commodity trading purchases and sales transactions are presented gross as expense and revenues for the FERC presentation; however, the net margin is reported as net sales for the GAAP presentation.
- Various revenues and expenses are presented as other income and income deductions for the FERC presentation and reported as operating income and expenses for the GAAP presentation.

Plant, Retirements and Depreciation

Utility plant is stated at original cost. The cost of additions includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction. The amount of interest capitalized on electric utility plant was \$495,000 in 2016 and \$723,000 in 2015. The cost of depreciable units of property retired less salvage is charged to accumulated depreciation. Removal costs, when incurred, are charged against the accumulated reserve for estimated removal costs. Maintenance, repairs and replacement of minor items of property are charged to operating expenses. The provisions for utility depreciation for financial reporting purposes are made on the straight-line method based on the estimated remaining service lives of the properties (5 to 82 years). Such provisions as a percent of the average balance of depreciable electric utility property were 2.88% in 2016 and 2.61% in 2015. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Recoverability of Long-Lived Assets

OTP reviews its long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. OTP determines potential impairment by comparing the carrying amount of the assets with net cash flows expected to be provided by operating activities of the business or related assets. If the sum of the expected future net cash flows is less than the carrying amount of the assets, OTP would recognize an impairment loss. Such an impairment loss would be measured as the amount by which the carrying amount exceeds the fair value of the asset, where fair value is based on the discounted cash flows expected to be generated by the asset.

Jointly Owned Facilities

OTP is a joint owner in two coal-fired steam-powered electric generation plants: Big Stone Plant near Big Stone City, South Dakota and Coyote Station near Beulah, North Dakota. OTP is also a joint owner, with other regional utilities, in three major in-service

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

transmission lines and two additional major transmission lines under construction. The following table provides ownership percentages and amounts included in OTP's December 31, 2016 and 2015 balance sheets for its share of jointly owned assets in each of these jointly owned facilities:

Jointly Owned Facilities (dollars in thousands)	OTP	Electric Plant in Service	Construction	Accumulated Depreciation	Net Plant
	Ownership Percentage		Work in Progress		
December 31, 2016					
Big Stone Plant	53.9%	\$ 328,809	\$ 23	\$ (65,665)	\$ 263,167
Coyote Station	35.0%	176,315	113	(101,499)	74,929
Fargo-Monticello 345 kiloVolt (kV) line	14.2%	78,298	--	(3,511)	74,787
Brookings-Southeast Twin Cities 345 kV line ¹	4.8%	26,406	--	(924)	25,482
Bemidji-Grand Rapids 230 kV line	14.8%	16,331	--	(1,573)	14,758
Big Stone South to Brookings 345 kV line ¹	50.0%	--	45,050	--	45,050
Big Stone South to Ellendale 345 kV line ¹	50.0%	--	49,160	--	49,160
December 31, 2015					
Big Stone Plant	53.9%	\$ 327,474	\$ (305)	\$ (57,641)	\$ 269,528
Coyote Station	35.0%	165,497	7,405	(103,822)	69,080
Fargo-Monticello 345 kV line	14.2%	78,272	--	(2,213)	76,059
Brookings-Southeast Twin Cities 345 kV line ¹	4.8%	26,189	--	(486)	25,703
Bemidji-Grand Rapids 230 kV line	14.8%	16,331	--	(1,233)	15,098
Big Stone South to Brookings 345 kV line ¹	50.0%	--	14,210	--	14,210
Big Stone South to Ellendale 345 kV line ¹	50.0%	--	8,335	--	8,335

¹MISO Multi-Value Project (MVP) designation provides for a return on invested funds while under construction under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff).

OTP's share of direct revenue and expenses of the jointly owned facilities is included in operating revenue and expenses in the statements of income.

Coyote Station Lignite Supply Agreement – Variable Interest Entity—In October 2012, the Coyote Station owners, including OTP, entered into a lignite sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (CCMC), a subsidiary of The North American Coal Corporation, for the purchase of lignite coal to meet the coal supply requirements of Coyote Station for the period beginning in May 2016 and ending in December 2040. The price per ton paid by the Coyote Station owners under the LSA reflects the cost of production, along with an agreed profit and capital charge. CCMC was formed for the purpose of mining coal to meet the coal fuel supply requirements of Coyote Station from May 2016 through December 2040 and, based on the terms of the LSA, is considered a variable interest entity (VIE) due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so that the price of the coal would cover all costs of operations as well as future reclamation costs. The Coyote Station owners are also providing a guarantee of the value of the assets of CCMC as they would be required to buy certain assets at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of CCMC in that they are required to buy the entity at the end of the contract term at equity value. Under current accounting standards, the primary beneficiary of a VIE is required to include the assets, liabilities, results of operations and cash flows of the VIE in its consolidated financial statements. No single owner of Coyote Station owns a majority interest in Coyote Station and none, individually, has the power to direct the activities that most significantly impact CCMC. Therefore, none of the owners individually, including OTP, is considered a primary beneficiary of the VIE. Therefore, CCMC is not required to be consolidated in OTP's financial statements.

If the LSA terminates prior to the expiration of its term or the production period terminates prior to December 31, 2040 and the Coyote Station owners purchase all of the outstanding membership interests of CCMC as required by the LSA, the owners will satisfy, or (if permitted by CCMC's applicable lender) assume, all of CCMC's obligations owed to CCMC's lenders under its loans and leases. The Coyote Station owners have limited rights to assign their rights and obligations under the LSA without the consent of CCMC's lenders during any period in which CCMC's obligations to its lenders remain outstanding. Coyote Station started taking delivery of coal and paying for coal and accumulated development fees and capital charges under the LSA in May 2016. In the event the contract is terminated because regulations or legislation render the burning of coal cost prohibitive and the assets worthless, OTP's maximum exposure to loss as a result of its involvement with CCMC as of December 31, 2016 could be as high as \$60.6 million, OTP's 35%

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

share of unrecovered costs.

Income Taxes

Deferred income taxes arise for all temporary differences between the book and tax basis of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect in the periods when the temporary differences reverse. OTP amortizes investment tax credits over the estimated lives of related property. OTP records income taxes in accordance with ASC Topic 740 (ASC 740), *Income Taxes*, and has recognized in its financial statements the tax effects of all tax positions that are “more-likely-than-not” to be sustained on audit based solely on the technical merits of those positions as of the balance sheet date. The term “more-likely-than-not” means a likelihood of more than 50%. See note 12 regarding OTP’s accounting for uncertain tax positions.

Otter Tail Corporation and its subsidiaries, including OTP, file a consolidated U.S. federal income tax return and various state income tax returns. In OTP’s financial statements, comprehensive interperiod income tax allocation is used for substantially all book and tax temporary differences. In accordance with ASC 740, OTP records separate company deferred tax attribute balances as if OTP filed separate tax returns. OTP’s deferred tax assets included \$7.9 million and \$8.3 million of deferred taxes associated with net operating losses that had been utilized by the consolidated group as of December 31, 2016 and 2015, respectively. This deferred tax asset would be reclassified to an intercompany receivable asset in the event the entity were to leave the consolidated return filing group.

OTP also is required to assess the realizability of its deferred tax assets, taking into consideration its forecast of future taxable income, the reversal of other existing temporary differences, available net operating loss carryforwards and available tax planning strategies that could be implemented to realize the deferred tax assets. Based on this assessment, management must evaluate the need for, and amount of, valuation allowances against OTP’s deferred tax assets. To the extent facts and circumstances change in the future, adjustments to the valuation allowance may be required.

Revenue Recognition

Customer electricity use is metered and bills are rendered monthly. Revenue is accrued for electricity consumed but not yet billed. Rate schedules applicable to substantially all customers include a fuel clause adjustment, under which the rates are adjusted to reflect changes in average cost of fuels and purchased power, and a surcharge for recovery of conservation-related expenses. Revenue is recognized for fuel and purchased power costs incurred in excess of amounts recovered in base rates but not yet billed through the fuel clause adjustment, for conservation program incentives and bonuses earned but not yet billed and for renewable resource, transmission-related and environmental incurred costs and investment returns approved for recovery through riders.

Revenues on wholesale electricity sales from company-owned generating units are recognized when energy is delivered. For shared use of transmission facilities with certain regional transmission cooperatives, revenues are estimated. Bills are rendered based on anticipated usage and settlements are made later based on actual usage. Estimated revenues may be adjusted prior to settlement, or at the time of settlement, to reflect actual usage.

Under ASC 815, OTP accounts for forward energy contracts as derivatives subject to mark-to-market accounting unless those contracts meet the definition of a capacity contract or are not subject to unplanned netting, then OTP accounts for the contracts under the normal purchases and sales exception to mark-to-market accounting.

Use of Estimates

OTP uses estimates based on the best information available in recording transactions and balances resulting from business operations. As better information becomes available (or actual amounts are known), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash Equivalents

OTP considers all highly liquid debt instruments purchased with maturity of 90 days or less to be cash equivalents.

Investments

The following table provides a breakdown of OTP’s investments at December 31:

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

<i>(in thousands)</i>	2016	2015
Cost Method – Economic Development Loan Pools	\$ 54	\$ 81
Equity Method – Partnership	23	22
Total Investments	\$ 77	\$ 103

Agreements Subject to Legally Enforceable Netting Arrangements

OTP does not offset assets and liabilities under legally enforceable netting arrangements on the face of its balance sheet.

Fair Value Measurements

OTP follows ASC Topic 820, *Fair Value Measurements and Disclosures* (ASC 820), for recurring fair value measurements. ASC 820 provides a single definition of fair value, requires enhanced disclosures about assets and liabilities measured at fair value and establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value.

Outside of pension plan assets, disclosed in note 9 to these financial statements, the only assets or liabilities on OTP's balance sheet at December 31, 2015 and during 2016 that were adjusted to fair value on a recurring basis were liabilities for valuation losses associated with forward gasoline purchase contracts. The valuation techniques and inputs used for forward gasoline purchase contracts are priced based on NYMEX quoted prices for Reformulated Blendstock for Oxygenate Blending (RBOB) Gasoline contracts. Prices used for the fair valuation of these contracts are based on NYMEX daily reporting date quoted prices for RBOB contracts with the same settlement periods, resulting in these loss positions being classified in level 2 of the fair value hierarchy. As of December 31, 2016 OTP held no forward gasoline purchase contracts.

The following table presents, for each of the hierarchy levels, OTP's liabilities measured at fair value on a recurring basis as of December 31, 2016 and December 31, 2015:

December 31, 2016 <i>(in thousands)</i>	Level 1	Level 2	Level 3
Liabilities:			
Derivative Liabilities – Forward Gasoline Purchase Contracts		\$ --	
December 31, 2015	Level 1	Level 2	Level 3
Liabilities:			
Derivative Liabilities – Forward Gasoline Purchase Contracts		\$ 199	

Inventories

OTP inventories consisting of fuel, materials and supplies are reported at average cost.

Supplemental Disclosures of Cash Flow Information

<i>(in thousands)</i>	As of December 31,	
	2016	2015
Noncash Investing Activities:		
Transactions Related to Capital Additions not Settled in Cash	\$ 13,421	\$ 19,004
<i>(in thousands)</i>	2016	2015
Cash Paid During the Year for:		
Interest (net of amount capitalized)	\$ 24,322	\$ 23,613
Income Tax Payments	\$ --	\$ --

New Accounting Standards

Accounting Standards Update (ASU) 2014-09—In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* (ASC 606). ASC 606 is a comprehensive, principles-based accounting standard which amends current revenue recognition guidance with the objective of improving revenue recognition requirements by providing a single comprehensive model to determine the measurement of revenue and the timing of revenue recognition. ASC 606 also requires expanded disclosures to enable

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

Amendments to the ASC in ASU 2014-09, as amended, are effective for fiscal years beginning after December 15, 2017. Early adoption is permitted, but not any earlier than January 1, 2017. Application methods permitted are: (1) full retrospective, (2) retrospective using one or more practical expedients and (3) retrospective with the cumulative effect of initial application recognized at the date of initial application. As of December 31, 2016 OTP has reviewed its revenue streams and contracts to determine areas where the amendments in ASU 2014-09 will be applicable and is evaluating transition options. Based on review, OTP does not anticipate a significant change in the levels or timing of revenue recognition over an annual or interim period as a result of the adoption of ASU 2014-09, with the exception of the treatment of contributions in aid of construction on which consensus treatment has not been determined and guidance has not been provided. Currently, OTP reduces its investment in fixed assets for the amount of these contributions. Should OTP be required to recognize these contributions as revenue under ASU 2014-09, it could result in a significant increase in reported revenues and expenses. Adoption of ASU 2014-09 will result in additional disclosures related to the nature, timing and certainty of revenues and any contract assets or liabilities that may be required to be reported under the updated standard. OTP does not plan to adopt the updated guidance prior to January 1, 2018.

ASU 2015-11—In July 2015, the FASB issued ASU No. 2015-11, *Inventory (Topic 330): Simplifying the Measurement of Inventory*, which requires that inventories be measured at the lower of cost or net realizable value instead of the lower of cost or market value. Net realizable value is defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The standards update is effective prospectively for fiscal years and interim periods beginning after December 15, 2016, with early adoption permitted. OTP does not expect the adoption of the updated standard to have a material impact on its financial statements.

ASU 2016-02—In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 is a comprehensive amendment of the ASC, creating Topic 842, which will supersede the current requirements under ASC Topic 840 on leases and require the recognition of lease assets and lease liabilities on the balance sheet and the disclosure of key information about leasing arrangements. Topic 842 affects any entity that enters into a lease, with some specified scope exemptions. The main difference between previous Generally Accepted Accounting Principles in the United States (GAAP) and Topic 842 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. Topic 842 retains a distinction between finance leases and operating leases. The classification criteria for distinguishing between finance leases and operating leases are substantially similar to the classification criteria for distinguishing between capital leases and operating leases in the previous guidance. Topic 842 also requires qualitative and specific quantitative disclosures by lessees and lessors to meet the objective of enabling users of financial statements to assess the amount, timing, and uncertainty of cash flows arising from leases. The amendments in ASU 2016-02 are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application of the amendments in ASU 2016-02 is permitted. OTP is currently reviewing ASU 2016-02, identifying key impacts to its businesses to determine areas where the amendments in ASU 2016-02 will be applicable and evaluating transition options. OTP does not currently plan to apply the amendments in ASU 2016-02 to its financial statements prior to 2019.

Subsequent Events – Management has evaluated the impact of events occurring after December 31, 2016 up to March 1, 2017, the date the Company’s U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 4, 2017. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

2. Rate and Regulatory Matters

Below are descriptions of OTP’s major capital expenditure projects and use of reagents and emission allowances that have had, or will have, a significant impact on OTP’s revenue requirements, rates and alternative revenue recovery mechanisms, followed by summaries of specific electric rate or rider proceedings with the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC), the South Dakota Public Utilities Commission (SDPUC) and the FERC, impacting OTP’s revenues in 2016 and 2015.

Major Capital Expenditure Projects

The Big Stone South – Brookings MVP and Capacity Expansion 2020 (CapX2020) Project—This 345 kV transmission line,

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

currently under construction, will extend approximately 70 miles between a substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Northern States Power – MN, a subsidiary of Xcel Energy Inc., jointly developed this project and the parties will have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Tariff in December 2011. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple areas within the MISO region. The cost allocation is designed to ensure the costs of transmission projects with regional benefits are properly assigned to those who benefit. Construction began on this line in the third quarter of 2015 and the line is expected to be in service in fall 2017.

The Big Stone South – Ellendale MVP—This is a 345 kV transmission line that will extend 163 miles between a substation near Big Stone City, South Dakota and a substation near Ellendale, North Dakota. OTP jointly developed this project with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., and the parties will have equal ownership interest in the transmission line portion of the project. MISO approved this project as an MVP under the MISO Tariff in December 2011. Construction began on this line in the second quarter of 2016 and is expected to be completed in 2019.

CapX2020 Transmission Line Projects—CapX2020 is a joint initiative of eleven investor-owned, cooperative, and municipal utilities in Minnesota and the surrounding region to upgrade and expand the electric transmission grid to ensure continued reliable and affordable service.

Fargo–Monticello 345 kV CapX2020 Project—OTP has invested approximately \$81 million and has a 14.2% ownership interest in the jointly-owned assets of this 240-mile transmission line, and owns 100% of certain assets of the project. The final phase of this project was energized on April 2, 2015.

Brookings–Southeast Twin Cities 345 kV CapX2020 Project (the Brookings Project)—OTP has invested approximately \$26 million and has a 4.8% ownership interest in this 250-mile transmission line. The MISO granted unconditional approval of the Brookings Project as an MVP under the MISO Tariff in December 2011. The final segments of this line were energized on March 26, 2015.

Big Stone Plant Air Quality Control System (AQCS)—OTP completed construction and testing of the Big Stone Plant AQCS in the fourth quarter of 2015 and placed the AQCS into commercial operation on December 29, 2015. OTP’s capitalized cost of the project, excluding allowance for funds used during construction, was approximately \$200 million.

Recovery of OTP’s major transmission investments is through the MISO Tariff (several as MVPs) and, currently, Minnesota, North Dakota and South Dakota Transmission Cost Recovery (TCR) Riders.

Reagent Costs

OTP’s systemwide costs for reagents are expected to increase to approximately \$2.2 million annually through May 2021 when Hoot Lake Plant is expected to be retired. The Minnesota, North Dakota and South Dakota share of costs are approximately 50%, 40% and 10%, respectively. Reagent costs for the Big Stone Plant AQCS and Coyote Station and Hoot Lake Plant Mercury and Air Toxics Standards (MATS) were initially incurred in 2015 when projects went into service.

Minnesota

2016 General Rate Case—On February 16, 2016 OTP filed a request with the MPUC for an increase in revenue recoverable under general rates in Minnesota. In its filing, OTP requested an allowed rate of return on rate base of 8.07% and an allowed rate of return on equity of 10.4% based on an equity ratio of 52.5% of total capital. On April 14, 2016 the MPUC issued an order approving an interim rate increase of 9.56% to the base rate portion of customers’ bills effective April 16, 2016, as modified and subject to refund. The request and interim rate information is detailed in the table below:

<i>(\$ in thousands)</i>	<i>(\$ in thousands)</i>	Annualized or Test Year	Actual Through December 31, 2016
Revenue Increase Requested	\$ 19,296		
Increase Percentage Requested	9.80%		
Jurisdictional Rate Base	\$483,000		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Interim Revenue Increase (subject to refund) \$ 16,816 \$ 10,976

The major components of the requested rate increase are summarized below:

Revenue Requirement Deficiency Cost Factors <i>(in thousands)</i>	2016 Test Year Allocation
Increased Rate Base	\$ 10,000
Increased Expenses	7,700
Other	1,596
Total Requested Revenue Increase	\$ 19,296
Excluded from Interim Rates: Rate Base Effect of Prepaid Pension Asset	(2,480)
Approved Interim Revenue Increase (subject to refund)	\$ 16,816

The deadline for submission of intervenor direct testimony was August 16, 2016. Direct testimony of the Minnesota Department of Commerce (MNDOC) included a recommendation for an 8.87% allowed rate of return on equity, and direct testimony of the Minnesota Office of the Attorney General (OAG) included a recommendation for a 6.96% allowed rate of return on equity. In response, in rebuttal testimony, OTP modified its request to provide for an allowed rate of return on equity of 10.05%. In rebuttal testimony, the MNDOC revised its recommendation to an 8.66% allowed rate of return on equity, and the Minnesota OAG revised its recommendation to a 7.14% allowed rate of return on equity. Hearings before the Administrative Law Judge (ALJ) occurred in October 2016. On January 5, 2017 the ALJ issued his report which included a recommendation for a 9.54% allowed rate of return on equity.

Based on OTP's modifications to its original request and other expected outcomes in the aforementioned rate case, OTP has recorded an estimated interim rate refund of \$3.6 million as of December 31, 2016. Oral arguments before the MPUC occurred in late February 2017. The MPUC made its final decision on March 2, 2017 granting OTP a 9.41% ROE. The final written Order is still forthcoming, but OTP estimates it will result in an insignificant adjustment to the previously accrued refund.

2010 General Rate Case—OTP's most recently completed general rate increase in Minnesota of approximately \$5.0 million, or 1.6%, was granted by the MPUC in an order issued on April 25, 2011 and effective October 1, 2011. Pursuant to the order, OTP's allowed rate of return on rate base increased from 8.33% to 8.61% and its allowed rate of return on equity increased from 10.43% to 10.74%.

Minnesota Conservation Improvement Programs—Under Minnesota law, every regulated public utility that furnishes electric service must make annual investments and expenditures in energy conservation improvements, or make a contribution to the state's energy and conservation account, in an amount equal to at least 1.5% of its gross operating revenues from service provided in Minnesota.

The MNDOC may require a utility to make investments and expenditures in energy conservation improvements whenever it finds that the improvement will result in energy savings at a total cost to the utility less than the cost to the utility to produce or purchase an equivalent amount of a new supply of energy. Such MNDOC orders can be appealed to the MPUC. Investments made pursuant to such orders generally are recoverable costs in rate cases, even though ownership of the improvement may belong to the property owner rather than the utility. OTP recovers conservation related costs not included in base rates under the Minnesota Conservation Improvement Program (MNCIP) through the use of an annual recovery mechanism approved by the MPUC.

On July 9, 2015 the MPUC granted approval of OTP's 2014 financial incentive of \$3.0 million along with an updated surcharge with an effective date of October 1, 2015.

Based on results from the 2015 MNCIP program year, OTP recognized a financial incentive of \$4.2 million. The 2015 MNCIP program resulted in an approximate 39% increase in energy savings compared to 2014 program results. On April 1, 2016 OTP requested approval for recovery of its 2015 MNCIP program costs not included in base rates, a \$4.3 million financial incentive and an update to the MNCIP surcharge from the MPUC. On July 19, 2016 the MPUC issued an order approving OTP's request with an effective date of October 1, 2016.

Based on results from the 2016 MNCIP program year, OTP recognized a financial incentive of \$5.1 million in 2016. The 2016 program resulted in an approximate 18% increase in energy savings compared to 2015 program results. OTP will request approval for recovery of its 2016 MNCIP program costs not included in base rates, a \$5.1 million financial incentive and an update to the MNCIP

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

surcharge from the MPUC by April 1, 2017.

On May 25, 2016 the MPUC adopted the MNDOC's proposed changes to the MNCIP financial incentive. The new model will provide utilities an incentive of 13.5% of 2017 net benefits, 12% of 2018 net benefits and 10% of 2019 net benefits, assuming the utility achieves 1.7% savings compared to retail sales. OTP estimates the impact of the new model will reduce the MNCIP financial incentive by approximately 50% compared to the previous incentive mechanism.

Transmission Cost Recovery Rider—The Minnesota Public Utilities Act (the MPU Act) provides a mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new transmission facilities that have been previously approved by the MPUC in a Certificate of Need (CON) proceeding, certified by the MPUC as a Minnesota priority transmission project, made to transmit the electricity generated from renewable generation sources ultimately used to provide service to the utility's retail customers, or exempt from the requirement to obtain a Minnesota CON. The MPUC may also authorize cost recovery via such TCR riders for charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the MISO to benefit the utility or integrated transmission system. The MPU Act also authorizes TCR riders to recover the costs of new transmission facilities approved by the regulatory commission of the state in which the new transmission facilities are to be constructed, to the extent approval is required by the laws of that state, and determined by the MISO to benefit the utility or integrated transmission system. Finally, under certain circumstances, the MPU Act also authorizes TCR riders to recover the costs associated with distribution planning and investments in distribution facilities to modernize the utility grid. Such TCR riders allow a return on investment at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule.

MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from other MISO customers. OTP is seeking recovery of capitalized internal costs and costs in excess of CON estimates related to a CapX2020 project in its current general rate case filing in Minnesota.

On February 18, 2015 the MPUC approved OTP's 2014 TCR rider annual update with an effective date of March 1, 2015. OTP filed an annual update to its Minnesota TCR rider on September 30, 2015 requesting revenue recovery of approximately \$7.8 million. A supplemental filing to the update was made on December 21, 2015 to address an issue surrounding the proration of accumulated deferred income taxes and, in an unrelated adjustment, the TCR rider update revenue request was reduced to \$7.2 million. On March 9, 2016 the MPUC issued an order approving OTP's annual update to its TCR rider, with an effective date of April 1, 2016.

OTP filed an update to its TCR rider on April 29, 2016 to incorporate the impact of bonus depreciation for income taxes, an adjusted rate of return on rate base and allocation factors to align with its 2016 general rate case request. On July 5, 2016 the MPUC issued an order approving the proposed rates on a provisional basis, as recommended by the MNDOC. The proposed rate changes went into effect on September 1, 2016. The MPUC has granted extensions to the MNDOC to file initial comments in this docket until February 2, 2017.

In OTP's 2016 general rate case, the MNDOC has argued that the MPUC should require OTP to include in the TCR rider retail rate base 100% of OTP's investment in the Big Stone South – Brookings and Big Stone South – Ellendale MVP Projects and all revenues received from other utilities under MISO's tariffed rates as a credit in its TCR revenue requirement calculations. OTP has opposed this treatment, arguing that the projects are appropriately assigned to the FERC jurisdiction, and the FERC's determination of the projects' revenue requirements should not be altered by forcing the revenues into the retail revenue requirement calculations. In the general rate case proceeding, the ALJ has recommended that the MPUC should affirm OTP's treatment. If the MPUC finds that the MNDOC's treatment should be followed, it would result in the projects being treated as retail investments for Minnesota retail ratemaking purposes. Because the FERC's revenue requirements and authorized returns will vary from the MPUC revenue requirements and authorized returns for the project investments over the lives of the projects, the impact of this decision will vary over time and be dependent on the differences between the revenue requirements and returns in the two jurisdictions at any given time.

Environmental Cost Recovery (ECR) Rider—The ECR rider recoverable revenue requirements include recovery of and a return on OTP's net investment in the Big Stone Plant AQCS. The MPUC approved OTP's 2014 ECR rider annual update request on November 24, 2014 with an effective date of December 1, 2014. OTP filed its 2015 annual update on July 31, 2015, with a request to keep the 2014 annual update rate in place. On December 21, 2015 OTP filed a supplemental filing with updated financial information. The MPUC issued an order on March 9, 2016 approving OTP's request to leave the 2014 annual update rate in place. OTP filed an update to its Minnesota ECR rider on April 29, 2016 to incorporate the impact of bonus depreciation for income taxes, an adjusted rate

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

of return on rate base and allocation factors to align with its 2016 general rate case request, with an effective date of September 1, 2016. On July 5, 2016 the MPUC issued an order approving the proposed rates on a provisional basis and has since granted extensions to the MNDOC to file initial comments in this docket until February 2, 2017. Reply comments were due from OTP on February 13, 2017.

Reagent Costs and Emission Allowances—On July 31, 2014 OTP filed a request with the MPUC to revise its Fuel Clause Adjustment (FCA) rider in Minnesota to include recovery of reagent and emission allowance costs. On March 12, 2015 the MPUC denied OTP's request to revise its FCA rider to include recovery of these costs. These costs are included in OTP's 2016 general rate case in Minnesota and are being considered for recovery either through the FCA rider or general rates. These costs are currently being expensed as incurred.

North Dakota

General Rates—OTP's most recent general rate increase in North Dakota of \$3.6 million, or approximately 3.0%, was granted by the NDPSC in an order issued on November 25, 2009 and effective December 2009. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.62%, and its allowed rate of return on equity was set at 10.75%.

Renewable Resource Adjustment—OTP has a North Dakota Renewable Resource Adjustment (NDRRA) which enables OTP to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. This rider allows OTP to recover costs associated with new renewable energy projects as they are completed, along with a return on investment. The NDPSC approved OTP's 2014 annual update to the NDRRA, including a change in rate design from an amount per kwh consumed to a percentage of a customer's bill, on March 25, 2015 with an effective date of April 1, 2015. OTP submitted its 2015 annual update to the NDRRA rider rate on December 31, 2015 with a requested implementation date of April 1, 2016. On February 25, 2016 OTP made a supplemental filing to address the impact of bonus depreciation for income taxes and related deferred tax assets on the NDRRA, as well as an adjustment to the estimated amount of Federal Production Tax Credits used. The NDPSC approved the NDRRA 2015 annual update on June 22, 2016 with an effective date of July 1, 2016. The updated NDRRA reflects a reduction in the return on equity (ROE) component of the rate from 10.75%, approved in OTP's most recent general rate case, to 10.50%. OTP submitted its 2016 annual update to the NDRRA rider rate on December 30, 2016, requesting a decrease to the NDRRA rate from 7.573% to 7.005%, with a requested implementation date of April 1, 2017.

Transmission Cost Recovery Rider—North Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. For qualifying projects, the law authorizes a current return on CWIP and a return on investment at the level approved in the utility's most recent general rate case. The NDPSC approved OTP's 2014 annual update to its TCR rider rate on December 17, 2014 with an effective date of January 1, 2015. On August 31, 2015 OTP filed its 2015 annual update to its North Dakota TCR rider rate requesting recovery of approximately \$10.2 million for 2016 compared with \$8.5 million for 2015, including costs assessed by the MISO as well as new costs from the Southwest Power Pool (SPP) that OTP began incurring January 1, 2016. These new costs are associated with OTP's load connected to the transmission system of Central Power Electric Cooperative (CPEC). OTP's load became subject to SPP transmission-related charges when CPEC transmission assets were added to the SPP. The NDPSC approved OTP's 2015 annual update to its TCR rider rate on December 16, 2015, with an effective date of January 1, 2016. On September 1, 2016 OTP filed its annual update to the TCR rider requesting a revenue requirement of \$5.7 million, which includes a reduction of \$2.6 million for a projected over-collection for 2016. Primary drivers of the decrease from the 2015 updated rider rate include the impact of federal bonus depreciation and unresolved MISO ROE complaint proceedings. OTP filed a supplemental filing on September 14, 2016, requesting that the over-collection balance be spread over the next two years for purposes of reducing the volatility of the rates from year to year. The NDPSC approved the update on December 14, 2016. The new rates went into effect on January 1, 2017.

Environmental Cost Recovery Rider—The ECR rider recoverable revenue requirements include recovery of and a return on OTP's net investment in the Big Stone Plant AQCS. On March 31, 2015 OTP filed its annual update to the ECR. This update included a request to increase the ECR rider rate from 7.531% to 9.193% of base rates. The NDPSC approved the annual update on June 17, 2015 with an effective date of July 1, 2015, along with the approval of recovery of OTP's North Dakota jurisdictional share of Hoot Lake Plant MATS project costs.

On March 31, 2016 OTP filed its annual update to the ECR rider requesting a reduction in the rate from 9.193% to 7.904% of base

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

rates, or a revenue requirement reduction from \$12.2 million to \$10.4 million, effective July 1, 2016. The rate reduction request was primarily due to Otter Tail Corporation's 2015 bonus depreciation election for income taxes, which reduces revenue requirements. The filing was approved on June 22, 2016.

Reagent Costs and Emission Allowances—On July 31, 2014 OTP filed a request with the NDPSC to revise its FCA rider in North Dakota to include recovery of new reagent and emission allowance costs. On February 25, 2015 the NDPSC approved recovery of these costs through modification of the ECR rider, instead of recovery through the FCA as OTP had proposed. The ECR rider reagent and emissions allowance charge became effective May 1, 2015.

South Dakota

2010 General Rate Case—OTP's most recent general rate increase in South Dakota of approximately \$643,000 or approximately 2.32% was granted by the SDPUC in an order issued on April 21, 2011 and effective with bills rendered on and after June 1, 2011. Pursuant to the order, OTP's allowed rate of return on rate base was set at 8.50%.

Transmission Cost Recovery Rider—South Dakota law provides a mechanism for automatic adjustment outside of a general rate proceeding to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities. The SDPUC approved OTP's 2014 annual update on February 13, 2015 with an effective date of March 1, 2015. OTP filed its 2015 annual update on October 30, 2015 with a proposed effective date of March 1, 2016. A supplemental filing was made on February 3, 2016 to true-up the filing to include the impact of bonus depreciation elected for 2015, the inclusion of a deferred tax asset relating to a net operating loss and the proration of accumulated deferred income taxes. This update included the recovery of new SPP transmission costs OTP began to incur on January 1, 2016. On February 12, 2016 the SDPUC approved OTP's annual update to its TCR rider, with an effective date of March 1, 2016. On November 1, 2016 OTP filed the annual update to the South Dakota TCR rider. OTP made a supplemental filing on January 20, 2017 to include updated costs through December 2016 as well as updated forecast information. The proposed effective date of the new rates is March 1, 2017.

Environmental Cost Recovery Rider—On November 25, 2014 the SDPUC approved OTP's ECR rider request to recover OTP's South Dakota jurisdictional share of revenue requirements associated with its investment in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects, with an effective date of December 1, 2014. On August 31, 2015 OTP filed its annual update to the South Dakota ECR requesting recovery of approximately \$2.7 million in annual revenue. The SDPUC approved the request on October 15, 2015 with an effective date of November 1, 2015. On August 31, 2016 OTP filed its 2016 update to the ECR rider, requesting recovery of approximately \$2.3 million in annual revenue. The SDPUC approved the request on October 26, 2016 with an effective date of November 1, 2016. The lower revenue requirement is a result of the implementation of federal bonus depreciation taken on the Big Stone Plant AQCS.

Reagent Costs and Emission Allowances—On August 1, 2014 OTP filed a request with the SDPUC to revise its FCA rider in South Dakota to include recovery of reagent and emission allowance costs. On September 16, 2014 the SDPUC approved OTP's request to include recovery of these costs in its South Dakota FCA rider.

Revenues Recorded under Rate Riders

The following table presents revenue recorded by OTP under rate riders in place in Minnesota, North Dakota and South Dakota for the years ended December 31:

Rate Rider (<i>in thousands</i>)	2016	2015
Minnesota		
Conservation Improvement Program Costs and Incentives ¹	\$12,920	\$10,724
Environmental Cost Recovery	12,443	10,238
Transmission Cost Recovery	5,795	5,202
North Dakota		
Environmental Cost Recovery	11,089	9,502
Renewable Resource Adjustment	7,800	8,409
Transmission Cost Recovery	7,694	6,609
South Dakota		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Environmental Cost Recovery	2,538	1,967
Transmission Cost Recovery	1,820	1,290
Conservation Improvement Program Costs and Incentives	468	583

¹Includes MNCIP costs recovered in base rates.

FERC

Wholesale power sales and transmission rates are subject to the jurisdiction of the FERC under the Federal Power Act of 1935, as amended. The FERC is an independent agency with jurisdiction over rates for wholesale electricity sales, transmission and sale of electric energy in interstate commerce, interconnection of facilities, and accounting policies and practices. Filed rates are effective after a one-day suspension period, subject to ultimate approval by the FERC.

Multi-Value Transmission Projects—On December 16, 2010 the FERC approved the cost allocation for a new classification of projects in the MISO region called MVPs. MVPs are designed to enable the region to comply with energy policy mandates and to address reliability and economic issues affecting multiple transmission zones within the MISO region. The cost allocation is designed to ensure that the costs of transmission projects with regional benefits are properly assigned to those who benefit. On October 20, 2011 the FERC reaffirmed the MVP cost allocation on rehearing.

Effective January 1, 2012 the FERC authorized OTP to recover 100% of prudently incurred CWIP and Abandoned Plant Recovery on two projects approved by MISO as MVPs in MISO's 2011 Transmission Expansion Plan: the Big Stone South–Brookings MVP and the Big Stone South–Ellendale MVP.

On November 12, 2013 a group of industrial customers and other stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff. The complainants sought to reduce the 12.38% ROE used in MISO's transmission rates to a proposed 9.15%. The complaint established a 15-month refund period from November 12, 2013 to February 11, 2015. On October 16, 2014 the FERC issued an order finding that the current MISO ROE may be unjust and unreasonable and setting the issue for hearing. Parties, including OTP, sought rehearing of the FERC's decision to set the November 12, 2013 complaint for hearing. This rehearing was denied on July 21, 2016. On September 19, 2016 the MISO transmission owners sought appeal to the United States Court of Appeals for the District of Columbia (D.C. Circuit). A non-binding decision by the presiding ALJ was issued on December 22, 2015 finding that the MISO transmission owners' ROE should be 10.32%, and the FERC issued an order on September 28, 2016 setting the base ROE at 10.32%.

On November 6, 2014 a group of MISO transmission owners, including OTP, filed for a FERC incentive of an additional 50-basis points for Regional Transmission Organization participation (RTO Adder). On January 5, 2015 the FERC granted the request, deferring collection of the RTO Adder until the FERC issued its order in the ROE complaint proceeding. Based on the FERC adjustment to the MISO Tariff ROE resulting from the November 12, 2013 complaint and OTP's incentive rate filing, OTP's ROE will be 10.82% (a 10.32% base ROE plus the 0.5% RTO Adder) effective September 28, 2016.

On February 12, 2015 another group of stakeholders filed a complaint with the FERC seeking to reduce the ROE component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff from 12.38% to a proposed 8.67%. This second complaint established a second 15-month refund period from February 12, 2015 to May 11, 2016. The FERC issued an order on June 18, 2015 setting the complaint for hearings before an ALJ, which were held the week of February 16, 2016. Parties, including OTP, sought rehearing of the FERC's decision to set the November 12, 2013 complaint for hearing. This rehearing was denied on July 21, 2016. On September 19, 2016 the MISO transmission owners sought appeal to the D.C. Circuit. A non-binding decision by the presiding ALJ was issued on June 30, 2016 finding that the MISO transmission owners' ROE should be 9.7%. The FERC is expected to issue its order not earlier than spring 2017.

Based on a potential reduction by the FERC in the ROE component of the MISO Tariff, OTP recorded reductions in revenue of \$1.6 million in 2016 and \$1.1 million in 2015 and has a \$2.7 million liability on its balance sheet as of December 31, 2016, representing OTP's best estimate of the refund obligations that would arise, net of amounts that would be subject to recovery under state jurisdictional TCR riders, based on a reduced ROE.

3. Regulatory Assets and Liabilities

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

As a regulated entity, OTP accounts for the financial effects of regulation in accordance with ASC 980. This accounting standard allows for the recording of a regulatory asset or liability for costs that will be collected or refunded in the future as required under regulation. Additionally, ASC 980-605-25 provides for the recognition of revenues authorized for recovery outside of a general rate case under alternative revenue programs which provide for recovery of costs and incentives or returns on investment in such items as transmission infrastructure, renewable energy resources or conservation initiatives. The following tables indicate the amount of other regulatory assets and liabilities recorded on OTP's balance sheets:

<i>(in thousands)</i>	December 31, 2016 Total	Remaining Recovery/ Refund Period
Other Regulatory Assets:		
Prior Service Costs and Actuarial Losses on Pensions and Other		
Postretirement Benefits ¹	\$114,710	see below
Deferred Marked-to-Market Losses ¹	10,530	48 months
Conservation Improvement Program Costs and Incentives ²	9,994	21 months
Accumulated ARO Accretion/Depreciation Adjustment ¹	6,153	asset lives
North Dakota Renewable Resource Rider Accrued Revenues ²	1,801	15 months
Minnesota Deferred Rate Case Expenses Subject to Recovery ¹	1,082	12 months
Deferred Income Taxes ¹	1,014	asset lives
North Dakota Transmission Cost Recovery Rider Accrued Revenues ²	568	24 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up ²	333	12 months
South Dakota Transmission Cost Recovery Rider Accrued Revenues ²	214	14 months
North Dakota Environmental Cost Recovery Rider Accrued Revenues ²	113	12 months
Minnesota Renewable Resource Rider Accrued Revenues ²	34	9 months
Total Other Regulatory Assets	\$146,546	
Other Regulatory Liabilities:		
North Dakota Transmission Cost Recovery Rider Accrued Refund	2,163	24 months
Revenue for Rate Case Expenses Subject to Refund – Minnesota	919	16 months
Deferred Income Taxes	818	asset lives
Minnesota Transmission Cost Recovery Rider Accrued Refund	757	12 months
South Dakota Environmental Cost Recovery Rider Accrued Refund	285	12 months
Minnesota Environmental Cost Recovery Rider Accrued Refund	139	12 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up	132	24 months
Other	110	204 months
Total Other Regulatory Liabilities	\$ 5,323	
Net Regulatory Asset Position	\$ 141,223	

¹Costs subject to recovery without a rate of return.

²Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.

<i>(in thousands)</i>	December 31, 2015 Total	Remaining Recovery/ Refund Period
Other Regulatory Assets:		
Prior Service Costs and Actuarial Losses on Pensions and Other		
Postretirement Benefits ¹	\$106,732	see below
Deferred Marked-to-Market Losses ¹	14,593	60 months
Conservation Improvement Program Costs and Incentives ²	8,677	18 months
Accumulated ARO Accretion/Depreciation Adjustment ¹	5,672	asset lives
North Dakota Renewable Resource Rider Accrued Revenues ²	1,266	15 months
Minnesota Deferred Rate Case Expenses Subject to Recovery ¹	291	12 months

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Deferred Income Taxes ¹	1,455	asset lives
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up ²	1,053	24 months
Minnesota Transmission Cost Recovery Rider Accrued Revenues ²	576	12 months
South Dakota Transmission Cost Recovery Rider Accrued Revenues ²	33	12 months
Minnesota Renewable Resource Rider Accrued Revenues ²	68	see below
Total Other Regulatory Assets	\$140,416	
Other Regulatory Liabilities:		
North Dakota Transmission Cost Recovery Rider Accrued Refund	132	12 months
Revenue for Rate Case Expenses Subject to Refund – Minnesota	1,279	see below
Deferred Income Taxes	1,109	asset lives
South Dakota Environmental Cost Recovery Rider Accrued Refund	185	12 months
Minnesota Environmental Cost Recovery Rider Accrued Refund	777	12 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	100	216 months
North Dakota Environmental Cost Recovery Rider Accrued Refund	321	12 months
North Dakota Renewable Resource Rider Accrued Refund	68	12 months
Total Other Regulatory Liabilities	\$ 3,971	
Net Regulatory Asset Position	\$ 136,445	

¹Costs subject to recovery without a rate of return.

²Amount eligible for recovery under an alternative revenue program which includes an incentive or rate of return.

The regulatory asset related to prior service costs and actuarial losses on pensions and other postretirement benefits represents benefit costs and actuarial losses subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs and actuarial losses are required to be recognized as components of Accumulated Other Comprehensive Income in equity under ASC Topic 715, *Compensation—Retirement Benefits*, but are eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates.

All Deferred Marked-to-Market Losses recorded as of December 31, 2016 relate to forward purchases of energy scheduled for delivery through December 2020.

Conservation Improvement Program Costs and Incentives represent mandated conservation expenditures and incentives recoverable through retail electric rates.

The Accumulated Asset Retirement Obligation (ARO) Accretion/Depreciation Adjustment will accrete and be amortized over the lives of property with asset retirement obligations.

North Dakota Renewable Resource Rider Accrued Revenues relate to qualifying renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of December 31, 2016.

Minnesota Deferred Rate Case Expenses Subject to Recovery relate to costs incurred in conjunction with OTP's 2016 rate case in Minnesota currently being recovered over a 24-month period beginning with the establishment of interim rates in April 2016.

The regulatory assets and liabilities related to Deferred Income Taxes result from changes in statutory tax rates accounted for in accordance with ASC Topic 740, *Income Taxes*.

The North Dakota Transmission Cost Recovery Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities that have not been billed to North Dakota customers as of December 31, 2016.

MISO Schedule 26/26A Transmission Cost Recovery Rider True-ups relate to the over/under collection of revenue based on comparison of the expected versus actual construction on eligible projects in the period. The true-ups also include the state jurisdictional portion of MISO Schedule 26/26A for regional transmission cost recovery that was included in the calculation of the state transmission riders and subsequently adjusted to reflect actual billing amounts in the schedule.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The South Dakota Transmission Cost Recovery Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities that have not been billed to South Dakota customers as of December 31, 2016.

The North Dakota Environmental Cost Recovery Rider Accrued Revenues relate to revenues earned on the North Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects that have not been billed to North Dakota customers as of December 31, 2016.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers. On April 4, 2013 the MPUC approved OTP's request to set the rider rate to zero effective May 1, 2013 and authorized that any unrecovered balance be retained as a regulatory asset to be recovered over an 18-month period beginning with the establishment of interim rates in April 2016.

The North Dakota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve North Dakota customers that are refundable to North Dakota customers as of December 31, 2016.

Revenue for Rate Case Expenses Subject to Refund – Minnesota relates to revenues collected under general rates to recover costs related to prior rate case proceedings in excess of the actual costs incurred, which are subject to refund over a 24-month period beginning with the establishment of interim rates in April 2016.

The Minnesota Transmission Cost Recovery Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve Minnesota customers that are refundable to Minnesota customers as of December 31, 2016.

The South Dakota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the South Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects that are refundable to South Dakota customers as of December 31, 2016.

The Minnesota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the Minnesota share of OTP's investment in the Big Stone Plant AQCS project that are refundable to Minnesota customers as of December 31, 2016.

If for any reason OTP ceases to meet the criteria for application of guidance under ASC 980 for all or part of its operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from OTP's balance sheet and included in OTP's statement of income as an expense or income item in the period in which the application of guidance under ASC 980 ceases.

4. Open Contract Positions Subject to Legally Enforceable Netting Arrangements

OTP has certain derivative contracts that are designated as normal purchases and carried at historical cost in the accompanying balance sheet. Individual counterparty exposures for these contracts can be offset according to legally enforceable netting arrangements. The following table shows the current fair value of these forward contract positions subject to legally enforceable netting arrangements as of December 31:

<i>(in thousands)</i>	2016	2015
Derivatives in Gain Positions Subject to Legally Enforceable Netting Arrangements	\$ --	\$ --
Open Contract Loss Positions Subject to Legally Enforceable Netting Arrangements	(17,382)	(16,070)
Net Balance Subject to Legally Enforceable Netting Arrangements	\$ (17,382)	\$ (16,070)

The following table provides a breakdown of OTP's credit risk standing on forward energy contracts in marked-to-market loss positions as of December 31:

<i>(in thousands)</i>	2016	2015
Loss Contracts Covered by Deposited Funds or Letters of Credit	\$ --	\$ 199
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade ¹	17,382	15,871

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Total Loss Contracts based on Current Market Values	\$ 17,382	\$ 16,070
<i>¹Certain OTP derivative energy contracts contain provisions that require an investment grade credit rating from each of the major credit rating agencies on OTP's debt. If OTP's debt ratings were to fall below investment grade, the counterparties to these forward energy contracts could request the immediate deposit of cash to cover contracts in net liability positions.</i>		
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade	\$ 17,382	\$ 15,871
Offsetting Gains with Counterparties under Master Netting Agreements	--	--
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	\$ 17,382	\$ 15,871

5. Common Shareholder's Equity

OTP has issued and outstanding 100 shares of common stock with a par value of \$5 per share, with the sole holder of these shares being Otter Tail Corporation. Otter Tail Corporation made cash equity contributions to OTP totaling \$37,000,000 in 2016 and \$43,728,000 in 2015.

6. Retained Earnings and Dividend Restriction

OTP's credit agreements contain restrictions on the payment of cash dividends upon a default or event of default. An event of default would be considered to have occurred if OTP did not meet certain financial covenants. As of December 31, 2016 OTP was in compliance with the debt covenants. See note 8 for further information on the covenants.

Under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. What constitutes "funds properly included in a capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials.

The MPUC indirectly limits the amount of dividends OTP can pay to Otter Tail Corporation by requiring an equity-to-total-capitalization ratio between 47.5% and 58.1% based on OTP's 2016 capital structure petition approved by order of the MPUC on August 2, 2016. As of December 31, 2016 OTP's equity-to-total-capitalization ratio including short-term debt was 52.9% and its net assets restricted from distribution totaled approximately \$440,000,000. Total capitalization for OTP cannot currently exceed \$1,123,168,000.

7. Commitments and Contingencies

Construction and Other Purchase Commitments

At December 31, 2016 OTP had commitments under contracts, including its share of construction program commitments, extending into 2019, of approximately \$84.8 million.

Electric Utility Capacity and Energy Requirements and Coal Contracts

OTP has commitments for the purchase of capacity and energy requirements under agreements extending into 2040. OTP has commitments under contracts providing for the purchase of a significant portion of its current coal requirements. Current coal purchase agreements for Big Stone Plant and Coyote Station expire in 2017 and 2040, respectively. In January 2016, OTP entered into an agreement with Cloud Peak Energy Resources LLC for the purchase of subbituminous coal for Hoot Lake Plant for the period of January 1, 2016 through December 31, 2023. OTP has no fixed minimum purchase requirements under the agreement but all of Hoot Lake Plant's coal requirements for the period covered must be purchased under this agreement. The dollar amounts of OTP's estimated purchase requirements under this agreement are excluded from the table below because OTP has not committed to any minimum level of purchases under the agreement. Fuel clause adjustment mechanisms lessen the risk of loss from market price changes because they provide for recovery of most fuel costs. See table below for schedule of commitments.

Operating Leases

OTP has obligations to make future operating lease payments primarily related to land leases and coal rail-car leases. Rent expense from operations was \$2,577,000 for 2016 and \$1,899,000 for 2015.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The amounts of OTP's construction program and other commitments and commitments under capacity and energy agreements, coal and coal delivery contracts and operating leases as of December 31, 2016, are as follows:

<i>(in thousands)</i>	Construction Program and Other Commitments	Capacity and Energy Requirements	Coal Purchase Commitments	Operating Leases
2017	\$ 74,328	\$ 23,711	\$ 30,699	\$ 2,374
2018	7,139	24,356	21,563	1,513
2019	3,331	24,925	22,102	1,237
2020	--	24,844	22,331	1,251
2021	--	12,988	22,840	1,103
Beyond 2021	--	166,137	550,719	9,396
Total	\$ 84,798	\$ 276,961	\$ 670,254	\$ 16,874

Contingencies

Based on the reduction by the FERC in the ROE component of the MISO Tariff, OTP has a \$2.7 million liability on its balance sheet as of December 31, 2016 representing OTP's best estimate of its current refund obligation related to amounts collected under the MISO Tariff, net of amounts that would be subject to recovery under state jurisdictional TCR riders.

Together with as many as 200 utilities, generators and power marketers, OTP participated in proceedings before the FERC regarding the calculation, assessment and implementation of MISO Revenue Sufficiency Guarantee (RSG) charges for entities participating in the MISO wholesale energy market since that market's start on April 1, 2005 until the conclusion of the proceedings on May 2, 2015. The proceedings fundamentally concerned MISO's application of its MISO RSG rate on file with the FERC to market participants, revisions to the RSG rate based on several FERC orders and the FERC's decision to resettle the markets based on MISO application of the RSG rate to market participants. Several of the FERC's orders are on review in a set of consolidated cases before the D.C. Circuit. The consolidated petitions at the D.C. Circuit involve multiple petitioners and intervenors. These consolidated cases are currently held in abeyance while the parties engage in mediation before the D.C. Circuit. OTP is an intervenor in these cases and a participant in mediation. The scope of the issues that will be subject to appeal at the D.C. Circuit have not yet been finalized. In addition, MISO has not made available past billing or resettlement data necessary for determining amounts that might be payable if the FERC's decisions are reversed. Therefore, OTP cannot estimate its exposure at this time from a final order reversing the relevant FERC orders. Although OTP cannot estimate its exposure at this time, a final order reversing the relevant FERC orders could have a material adverse effect on OTP's results of operations.

Contingencies, by their nature, relate to uncertainties that require OTP's management to exercise judgment both in assessing the likelihood a liability has been incurred as well as in estimating the amount of potential loss. The most significant contingencies that could potentially impact OTP's financial statements are those related to environmental remediation and litigation matters, but no estimates for potential losses have been made at this time, including any liability for RSG charges.

In 2014 the Environmental Protection Agency (EPA) published proposed standards of performance for carbon dioxide (CO₂) emissions from new fossil fuel-fired power plants, proposed CO₂ emission guidelines for existing fossil fuel-fired power plants and proposed CO₂ standards of performance for CO₂ emissions from reconstructed and modified fossil fuel-fired power plants under section 111 of the Clean Air Act. The EPA published final rules for each of these proposals on October 23, 2015. All of these rules have been challenged on legal grounds and are currently pending before the D.C. Circuit. On February 9, 2016 the U.S. Supreme Court granted a stay of the CO₂ emission guidelines for existing fossil fuel-fired power plants, pending disposition of petitions for review in the D.C. Circuit and, if a petition for a writ of certiorari seeking review by the U.S. Supreme Court were granted, any final Supreme Court determination. The D.C. Circuit heard oral argument on challenges to the CO₂ emission guidelines on September 27, 2016 before the full court, and a decision will likely be rendered in the first half of 2017. In addition, members of Congress and the new administration have been very critical of the Clean Power Plan (CPP) and may take actions that could impact the rule or the litigation. Therefore, while the CPP remains stayed, there is uncertainty regarding the future of the rule. The final outcome of this rulemaking process could have an adverse impact on OTP's business and results of operations.

Other

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

OTP is a party to litigation and regulatory enforcement matters arising in the normal course of business. OTP regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. OTP believes the effect on its operations, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2016 will not be material.

8. Short-Term and Long-Term Borrowings

Short-Term Debt

The following table presents the status of OTP's line of credit as of December 31, 2016 and December 31, 2015:

<i>(in thousands)</i>	Line Limit	In Use on December 31, 2016	Restricted due to Outstanding Letters of Credit	Available on December 31, 2016	Available on December 31, 2015
OTP Credit Agreement	\$ 170,000	\$ 42,883	\$ 50	\$ 127,067	\$ 148,694

Under the OTP Credit Agreement (as defined below), the maximum amount of debt outstanding in 2016 was \$51,885,000 on December 16, 2016 and the average daily balance of debt outstanding during 2016 was \$32,576,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2016 was 1.8% compared with 1.5% in 2015. The weighted average interest rate on OTP's short-term debt outstanding on December 31, 2016 was 1.9%.

On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement), providing for an unsecured \$170 million revolving credit facility that may be increased to \$250 million on the terms and subject to the conditions described in the OTP Credit Agreement. On October 31, 2016 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2020 to October 29, 2021. OTP can draw on this credit facility to support the working capital needs and other capital requirements of its operations, including letters of credit in an aggregate amount not to exceed \$50 million outstanding at any time. Borrowings under this line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on the ratings of OTP's senior unsecured debt. OTP is required to pay commitment fees based on the average daily unused amount available to be drawn under the revolving credit facility. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, make investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Credit Agreement also contains affirmative covenants and events of default, and financial covenants as described below under the heading "Financial Covenants." The OTP Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. OTP's obligations under the OTP Credit Agreement are not guaranteed by any other party.

Long-Term Debt

2013 Note Purchase Agreement

On August 14, 2013 OTP entered into a Note Purchase Agreement (the 2013 Note Purchase Agreement) pursuant to which OTP agreed to issue to the purchasers named therein, in a private placement transaction, \$60 million aggregate principal amount of OTP's 4.68% Series A Senior Unsecured Notes due February 27, 2029 (the Series A Notes) and \$90 million aggregate principal amount of OTP's 5.47% Series B Senior Unsecured Notes due February 27, 2044 (the Series B Notes and, together with the Series A Notes, the Notes). The Notes were issued on February 27, 2014. OTP used a portion of the proceeds of the Notes to retire early a \$40.9 million term loan then outstanding and to repay OTP's short-term debt outstanding on February 27, 2014. The remaining proceeds of the Notes were used to pay fees and expenses related to the issuance of the Notes and for other general purposes, including construction program expenditures.

The 2013 Note Purchase Agreement states that OTP may prepay all or any part of the Notes (in an amount not less than 10% of the aggregate principal amount of the Notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount, provided that if no default or event of default under the 2013 Note Purchase Agreement exists, any optional prepayment made by OTP of (i) all of the Series A Notes then outstanding on or after November 27, 2028 or (ii) all of the Series B Notes then outstanding on or after November 27, 2043, will be made at 100% of the principal prepaid but without any make-whole amount. In addition, the 2013 Note Purchase Agreement states OTP must offer to prepay all of the

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

outstanding Notes at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP.

The 2013 Note Purchase Agreement contains a number of restrictions on the business of OTP, including restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The 2013 Note Purchase Agreement also contains affirmative covenants and events of default, as well as certain financial covenants as described below under the heading "Financial Covenants." The 2013 Note Purchase Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in OTP's credit ratings. The 2013 Note Purchase Agreement includes a "most favored lender" provision generally requiring that in the event OTP's existing credit agreement or any renewal, extension or replacement thereof, at any time contains any financial covenant or other provision providing for limitations on interest expense and such a covenant is not contained in the 2013 Note Purchase Agreement under substantially similar terms or would be more beneficial to the holders of the Notes than any analogous provision contained in the 2013 Note Purchase Agreement (an "Additional Covenant"), then unless waived by the Required Holders (as defined in the 2013 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2013 Note Purchase Agreement. The 2013 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP credit agreement, provided that no default or event of default has occurred and is continuing.

2007 and 2011 Note Purchase Agreements

On December 1, 2011, OTP issued \$140 million aggregate principal amount of its 4.63% Senior Unsecured Notes due December 1, 2021 pursuant to a Note Purchase Agreement dated as of July 29, 2011 (the 2011 Note Purchase Agreement). OTP also has outstanding its \$155 million senior unsecured notes issued in four series consisting of \$33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017; \$30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022; \$42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027; and \$50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (collectively, the 2007 Notes). The 2007 Notes were issued pursuant to a Note Purchase Agreement dated as of August 20, 2007 (the 2007 Note Purchase Agreement).

The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each states that OTP may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. The 2011 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require OTP to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the 2011 Note Purchase Agreement. The 2011 Note Purchase Agreement and the 2007 Note Purchase Agreement each also states that OTP must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of OTP. The note purchase agreements contain a number of restrictions on OTP, including restrictions on OTP's ability to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The note purchase agreements also include affirmative covenants and events of default, and certain financial covenants as described below under the heading "Financial Covenants."

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2016 for each of the next five years are:

<i>(in thousands)</i>	2017	2018	2019	2020	2021
Aggregate Amounts of Debt Maturities	\$ 33,000	\$ --	\$ --	\$ --	\$140,000

Financial Covenants

OTP was in compliance with the financial covenants in their debt agreements as of December 31, 2016.

No Credit or Note Purchase Agreement contains any provisions that would trigger an acceleration of the related debt as a result of changes in the credit rating levels assigned to the related obligor by rating agencies.

OTP's borrowing agreements are subject to certain financial covenants. Specifically:

- Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

greater than 0.60 to 1.00.

- Under the 2007 Note Purchase Agreement and 2011 Note Purchase Agreement, OTP may not permit the ratio of its Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, in each case as provided in the related borrowing agreement, and OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement.
- Under the 2013 Note Purchase Agreement, OTP may not permit its Interest-bearing Debt to exceed 60% of Total Capitalization and may not permit its Priority Indebtedness to exceed 20% of its Total Capitalization, each as provided in the 2013 Note Purchase Agreement.

9. Pension Plan and Other Postretirement Benefits

For valuation of OTP's pension and other postretirement benefit plans' projected benefit obligations as of December 31, 2016, Otter Tail Corporation and OTP adopted updated and modified mortality tables and an updated and modified mortality improvement scale that projects lower mortality improvements in the future for plan participants. The adoption of the updated and modified mortality tables and mortality improvement scale in 2016 decreased OTP's pension and other postretirement benefit obligations from projected benefit obligations that would have been rendered using the mortality tables OTP had been using since 2014. Although the adoption of the updated and modified tables and improvement scale will have the effect of decreasing the estimated and recognized cost of future benefit payments in the near term, the ultimate cost recognized will be determined by the actual level and duration of future benefit payments.

Pension Plan

The noncontributory funded pension plan (the Plan) covers substantially all OTP nonunion employees hired prior to September 1, 2006, and all union employees of OTP hired prior to November 1, 2013, excluding Coyote Station employees. Coyote Station employees hired before January 1, 2009 are covered under the Plan. The Plan provides 100% vesting after five vesting years of service and for retirement compensation at age 65, with reduced compensation in cases of retirement prior to age 62. OTP reserves the right to discontinue the Plan but no change or discontinuance may affect the pensions theretofore vested.

The pension plan has a trustee who is responsible for pension payments to retirees and a separate pension fund manager responsible for managing the Plan's assets. An independent actuary assists in performing the necessary actuarial valuations for the Plan.

The plan assets consist of common stock and bonds of public companies, U.S. government securities, cash and cash equivalents and alternative investments. None of the Plan assets are invested in common stock or debt securities of OTP or Otter Tail Corporation.

Components of net periodic pension benefit cost:

<i>(in thousands)</i>	2016	2015
Service Cost—Benefit Earned During the Period	\$ 5,386	\$ 5,908
Interest Cost on Projected Benefit Obligation	13,854	13,010
Expected Return on Assets	(18,987)	(17,923)
Amortization of Prior-Service Cost from Regulatory Asset	189	188
Amortization of Net Actuarial Loss from Regulatory Asset	5,153	6,676
Net Periodic Pension Cost	\$ 5,595	\$ 7,859

Weighted average assumptions used to determine net periodic pension cost for the year ended December 31:

	2016	2015
Discount Rate	4.76%	4.35%
Long-Term Rate of Return on Plan Assets	7.75%	7.75%
Rate of Increase in Future Compensation Level	3.13%	3.13%

The following table presents amounts recognized in OTP's balance sheets as of December 31:

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2016	2016/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

<i>(in thousands)</i>	2016	2015
Regulatory Assets:		
Unrecognized Prior Service Cost	\$ 141	\$ 329
Unrecognized Actuarial Loss	98,039	101,974
Total Regulatory Assets	\$ 98,180	\$ 102,303
Noncurrent Liability	\$ 58,845	\$ 67,373

Funded status as of December 31:

<i>(in thousands)</i>	2016	2015
Accumulated Benefit Obligation	\$(274,660)	\$(261,677)
Projected Benefit Obligation	\$(307,086)	\$(295,171)
Fair Value of Plan Assets	248,241	227,798
Funded Status	\$ (58,845)	\$ (67,373)

The following tables provide a reconciliation of the changes in the OTP portion of the fair value of the Plan's assets and the Plan's benefit obligations over the two-year period ended December 31, 2016:

<i>(in thousands)</i>	2016	2015
Reconciliation of OTP's Portion of the Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	\$ 227,798	\$ 238,719
Actual Return on Plan Assets	23,404	(9,240)
Discretionary Company Contributions	10,000	10,000
Benefit Payments	(12,961)	(11,681)
Fair Value of Plan Assets at December 31	\$ 248,241	\$ 227,798
Estimated Asset Return	10.1%	(3.7)%
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 295,171	\$ 304,170
Service Cost	5,386	5,908
Interest Cost	13,854	13,010
Benefit Payments	(12,961)	(11,681)
Actuarial Loss (Gain)	5,636	(16,236)
Projected Benefit Obligation at December 31	\$ 307,086	\$ 295,171

Weighted average assumptions used to determine benefit obligations at December 31:

	2016	2015
Discount Rate	4.60%	4.76%
Rate of Increase in Future Compensation Level	3.00%	3.13%

The assumed rate of return on pension fund assets used for the determination of 2017 net periodic pension cost is 7.50%. The assumed long-term rate of return on plan assets is based primarily on asset category studies using historical market return and volatility data with forward looking estimates based on existing financial market conditions and forecasts of capital markets. Modest excess return expectations versus some market indices are incorporated into the return projections based on the actively managed structure of the investment programs and their records of achieving such returns historically. The rate of return on plan asset assumptions are reviewed annually. The assumptions are largely based on the asset category rate-of-return assumptions developed annually with the pension plan investment advisors, as well as input from actuaries who work with the pension plan.

Market-related value of plan assets—The expected return on plan assets is determined based on the expected long-term rate of return on plan assets and the market-related value of plan assets.

The actuarial determination of pension plan expense or income is based on a market-related valuation of assets, which reduces

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

year-to-year volatility. This market-related valuation calculation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related valuation calculation recognizes gains or losses over a five-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized.

Measurement Dates:	2016	2015
Net Periodic Pension Cost	January 1, 2016	January 1, 2015
	January 1, 2016 projected to	January 1, 2015 projected to
End of Year Benefit Obligations	December 31, 2016	December 31, 2015
Market Value of Assets	December 31, 2016	December 31, 2015

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets into the net periodic pension cost in 2017 are:

<i>(in thousands)</i>	2017
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 120
Amortization of Unrecognized Actuarial Loss	5,090
Total Estimated Amortization	\$ 5,210

Cash flows—OTP had no minimum funding requirement as of December 31, 2016 and will continue to evaluate if discretionary plan contributions will be made in 2017.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid out from plan assets:

<i>(in thousands)</i>	2017	2018	2019	2020	2021	Years 2022-2026
	\$13,285	\$14,004	\$14,663	\$15,415	\$16,179	\$91,199

The following objectives guide the investment strategy of the Plan:

- The assets of the Plan will be invested in accordance with all applicable laws in a manner consistent with fiduciary standards including Employee Retirement Income Security Act standards (if applicable). Specifically:
 - The safeguards and diversity that a prudent investor would adhere to must be present in the investment program.
 - All transactions undertaken on behalf of the Plan must be in the best interest of plan participants and their beneficiaries.
- The primary objective of the Plan is to provide a source of retirement income for its participants and beneficiaries.
- The near-term primary financial objective of the Plan is to improve the funded status of the Plan.
- A secondary financial objective is to minimize pension funding and expense volatility where possible.

The asset allocation strategy developed by the Retirement Plans Administration Committee (the Committee) is based on the current needs of the Plan and the objectives listed above. An asset/liability review is conducted annually or as often as necessary to assess the impact of various asset allocations on funded status and other financial variables. The current needs of the Plan, the overall investment objectives above, the investment preferences and risk tolerance of the Committee and the desired degree of diversification suggest the need for an investment allocation including multiple asset classes.

The asset allocation in the table below contains guideline percentages, at market value, of the total Plan invested in various asset classes. The Permitted Range is a guide and will at times not reflect the actual asset allocation as this will be dictated by market conditions, the independent actions of the Committee and/or Investment Managers and required cash flows to and from the Plan. The Permitted Range anticipates this fluctuation and provides flexibility for the Investment Managers' portfolios to vary around the target without the need for immediate rebalancing. The Investment Manager will proactively monitor the asset allocation and will direct the purchases and sales to remain within the stated ranges.

The policy of the Plan is to invest assets in accordance with the allocations shown below:

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Asset Class / PBO Funded Status	Permitted Range			
	< 100% PBO	100% PBO	105% PBO	>=110% PBO
Equity	30% - 65%	25% - 60%	20% - 55%	15% - 50%
Investment Grade Fixed Income	35% - 75%	40% - 80%	45% - 85%	50% - 90%
Below Investment Grade Fixed Income*	0% - 15%	0% - 15%	0% - 15%	0% - 15%
Other**	0% - 20%	0% - 20%	0% - 20%	0% - 20%

* Includes (but not limited to) High Yield Bond Fund and Emerging Markets Debt funds.

** Other category may include cash, alternatives, and/or other investment strategies that may be classified other than equity or fixed income, such as the Dynamic Asset Allocation fund.

OTP's pension plan asset allocations at December 31, 2016 and 2015, by asset category are as follows:

Asset Allocation	2016	2015
Large Capitalization Equity Securities	21.4%	21.2%
International Equity Securities	22.0%	21.6%
Small and Mid-Capitalization Equity Securities	9.0%	8.1%
SEI Dynamic Asset Allocation Fund	5.4%	5.6%
Equity Securities	57.8%	56.5%
Fixed-Income Securities and Cash	34.3%	35.8%
Other – SEI Energy Debt Collective Fund	4.1%	3.6%
Other – SEI Special Situation Collective Investment Trust	3.8%	4.1%
	100.0%	100.0%

The following table presents OTP's pension fund assets measured at fair value and included in Level 1 of the fair value hierarchy and assets measured using the net asset value (NAV) practical expedient to fair valuation as of December 31:

(in thousands)	2016	2015
Assets in Level 1 of the Fair Value Hierarchy	\$ 228,680	\$ 210,284
SEI Energy Debt Collective Fund at NAV	10,190	8,133
SEI Special Situation Collective Investment Trust Fund at NAV ⁽¹⁾	9,371	9,381
Total Assets	\$ 248,241	\$ 227,798

⁽¹⁾ On December 30, 2016 Otter Tail Corporation instructed the pension fund manager to sell the pension fund investment in the SEI Special Situation Collective Investment Trust Fund. The cash value of OTP's share of the investment on settlement of the sale in January 2017 was \$9,447,000.

Fair Value Measurements of Pension Fund Assets

ASC 715, *Compensation – Retirement Benefits*, requires disclosures about pension plan assets identified by the three levels of the fair value hierarchy established by ASC 820-10-35.

The following table presents OTP's pension fund assets measured at fair value and included in Level 1 of the fair value hierarchy as of December 31:

(in thousands)	2016	2015
Large Capitalization Equity Securities Mutual Fund	\$ 53,175	\$ 48,275
International Equity Securities Mutual Funds	54,574	49,241
Small and Mid-Capitalization Equity Securities Mutual Fund	22,459	18,353
SEI Dynamic Asset Allocation Mutual Fund	13,295	12,679
Fixed Income Securities Mutual Funds	85,174	81,734
Cash Management – Money Market Fund	3	2
Total Assets	\$ 228,680	\$ 210,284

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The investments held by the SEI Special Situation Collective Investment Trust on December 31, 2016 and 2015 consisted of investments primarily in hedge funds that pursue alternative strategies, private equity funds and hybrid funds, as well as investments directly in other securities and financial instruments, with the objective of achieving high returns balanced against an appropriate level of volatility and market exposure over a full market cycle. The NAV of the SEI Special Situations Collective Investment Trust is determined by using the fair value of the portfolio as of the close of business at the end of the year. The fair value of the fund is calculated independently by the fund's administrator and is reviewed by Otter Tail Corporation.

The investments held by the SEI Energy Debt Collective Fund on December 31, 2016 and 2015 consist mainly of below investment grade high yielding bonds and loans of U.S. energy companies which trade at a discount to fair value. Redemptions are allowed semi-annually with a 95-day notice period, subject to fund director consent and certain gate, holdback and suspension restrictions. Subscriptions are allowed monthly with a three-year lock up on subscriptions. Fund assets totaling \$10.0 million were invested in the SEI Energy Debt Fund in July 2015. The fund's assets are valued in accordance with valuations reported by the fund's sub-advisor or the fund's underlying investments or other independent third party sources, although SEI in its discretion may use other valuation methods, subject to compliance with ERISA (as applicable). The fund's assets are valued as of the close of business on the last business day of each calendar month and are available 30 days after the end of a calendar quarter. On an annual basis, as determined by the investment manager in its sole discretion, an independent valuation agent is retained to provide a valuation of the illiquid assets of the fund and of any other asset of the fund, as determined by the investment manager in its sole discretion. Otter Tail Corporation reviews and verifies the reasonableness of the year-end valuations.

Executive Survivor and Supplemental Retirement Plan (ESSRP)

The ESSRP is an unfunded, nonqualified benefit plan for Otter Tail Corporation and OTP executive officers and certain key management employees. The ESSRP provides defined benefit payments to these employees on their retirements for life or to their beneficiaries on their deaths for a 15-year postretirement period. There are no plan assets in this nonqualified benefit plan due to the nature of the plan.

Components of net periodic pension benefit cost:

<i>(in thousands)</i>	2016	2015
Service Cost—Benefit Earned During the Period	\$ 87	\$ 76
Interest Cost on Projected Benefit Obligation	782	728
Amortization of Prior Service Cost:		
From Regulatory Asset	16	16
From Other Comprehensive Income ¹	15	15
Amortization of Net Actuarial Loss:		
From Regulatory Asset	293	334
From Other Comprehensive Income ¹	272	310
Net Periodic Pension Cost	\$ 1,465	\$ 1,479

¹Amortization of Prior Service Costs and Net Actuarial Loss from Other Comprehensive Income Charged to Electric Operation and Maintenance Expenses

Weighted average assumptions used to determine net periodic pension cost for the year ended December 31:

	2016	2015
Discount Rate	4.76%	4.35%
Rate of Increase in Future Compensation Level	3.25%	3.25%

The following table presents amounts recognized in OTP's balance sheets as of December 31:

<i>(in thousands)</i>	2016	2015
Regulatory Assets:		
Unrecognized Prior Service Cost	\$ 58	\$ 75
Unrecognized Actuarial Loss	2,890	2,936

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Total Regulatory Assets	\$ 2,948	\$ 3,011
Projected Benefit Obligation Liability – Net Amount Recognized	\$(17,263)	\$(17,107)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	\$ 54	\$ 69
Unrecognized Actuarial Loss	2,682	2,725
Total Accumulated Other Comprehensive Loss	\$ 2,736	\$ 2,794

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations over the two-year period ended December 31, 2016 and a statement of the funded status as of December 31 of both years:

<i>(in thousands)</i>	2016	2015
Reconciliation of OTP's Portion of the Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	\$ --	\$ --
Actual Return on Plan Assets	--	--
Employer Contributions	1,188	1,119
Benefit Payments	(1,188)	(1,119)
Fair Value of Plan Assets at December 31	\$ --	\$ --
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 17,107	\$ 17,360
Service Cost	87	76
Interest Cost	782	728
Benefit Payments	(1,188)	(1,119)
Actuarial Loss	475	62
Projected Benefit Obligation at December 31	\$ 17,263	\$ 17,107

Weighted average assumptions used to determine benefit obligations at December 31:

	2016	2015
Discount Rate	4.60%	4.76%
Rate of Increase in Future Compensation Level	3.00%	3.25%

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost for the ESSRP in 2017 are:

<i>(in thousands)</i>	2017
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 16
Amortization of Unrecognized Actuarial Loss	285
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	16
Amortization of Unrecognized Actuarial Loss	264
Total Estimated Amortization	\$ 581

Cash flows—The ESSRP is unfunded and has no assets; contributions are equal to the benefits paid to plan participants. The following benefit payments, which reflect future service, as appropriate, are expected to be paid:

<i>(in thousands)</i>	Years					
	2017	2018	2019	2020	2021	2022-2026
	\$1,244	\$1,291	\$1,365	\$1,346	\$1,308	\$5,920

Other Postretirement Benefits

OTP provides a portion of health insurance and life insurance benefits for retired OTP employees. Substantially all of OTP's electric

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

utility employees may become eligible for health insurance benefits if they reach age 55 and have 10 years of service. There are no plan assets.

Components of net periodic postretirement benefit cost:

<i>(in thousands)</i>	2016	2015
Service Cost—Benefit Earned During the Period	\$ 1,270	\$ 1,264
Interest Cost on Projected Benefit Obligation	2,443	2,045
Amortization of Prior Service Cost from Regulatory Asset	134	205
Amortization of Net Actuarial Loss from Regulatory Asset	379	--
Net Periodic Postretirement Benefit Cost	\$ 4,226	\$ 3,514
Effect of Medicare Part D Subsidy	\$ (901)	\$ (1,450)

Weighted average assumptions used to determine net periodic postretirement benefit cost for the year ended December 31:

	2016	2015
Discount Rate	4.57%	4.20%

The following table presents amounts recognized in OTP's balance sheets as of December 31:

<i>(in thousands)</i>	2016	2015
Regulatory Asset:		
Unrecognized Prior Service Cost	\$ (4)	\$ 129
Unrecognized Net Actuarial Loss	13,586	1,289
Net Regulatory Asset	\$ 13,582	\$ 1,418
Projected Benefit Obligation Liability – Net Amount Recognized	\$ (61,070)	\$ (47,512)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations over the two-year period ended December 31, 2016:

<i>(in thousands)</i>	2016	2015
Reconciliation of OTP's Portion of the Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	\$ --	\$ --
Actual Return on Plan Assets	--	--
Company Contributions	2,832	2,336
Benefit Payments (Net of Medicare Part D Subsidy)	(5,888)	(5,286)
Participant Premium Payments	3,056	2,950
Fair Value of Plan Assets at December 31	\$ --	\$ --
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 47,512	\$ 52,337
Service Cost (Net of Medicare Part D Subsidy)	1,270	1,264
Interest Cost (Net of Medicare Part D Subsidy)	2,443	2,045
Benefit Payments (Net of Medicare Part D Subsidy)	(5,888)	(5,286)
Participant Premium Payments	3,056	2,950
Actuarial Loss (Gain)	12,677	(5,798)
Projected Benefit Obligation at December 31	\$ 61,070	\$ 47,512

Weighted average assumptions used to determine benefit obligations at December 31:

	2016	2015
Discount Rate	4.46%	4.57%

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Assumed healthcare cost-trend rates as of December 31:

	2016	2015
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	6.01%	6.16%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	6.23%	6.43%
Rate to Which the Cost-Trend Rate is Assumed to Decline	4.50%	4.50%
Year the Rate Reaches the Ultimate Trend Rate	2038	2038

Assumed healthcare cost-trend rates have a significant effect on the amounts reported for healthcare plans. A one-percentage-point change in assumed healthcare cost-trend rates for 2016 would have the following effects:

<i>(in thousands)</i>	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	\$ 6,979	\$ (7,313)
Effect on Total of Service and Interest Cost	\$ 637	\$ (506)
Effect on Expense	\$ 1,419	\$ (885)

Measurement Dates:	2016	2015
Net Periodic Postretirement Benefit Cost	January 1, 2016	January 1, 2015
End of Year Benefit Obligations	January 1, 2016 projected to December 31, 2016	January 1, 2015 projected to December 31, 2015

The estimated net amounts of unrecognized accumulated actuarial losses to be amortized from regulatory assets into the net periodic postretirement benefit cost in 2017 is \$932,000.

Cash flows—OTP expects to contribute \$3.4 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2017. OTP expects to receive a Medicare Part D subsidy from the Federal government of approximately \$406,000 in 2017. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

<i>(in thousands)</i>	2017	2018	2019	2020	2021	Years 2022-2026
	\$3,428	\$3,581	\$3,736	\$3,818	\$3,949	\$19,888

401K Plan

OTP has a 401K plan for the benefit of all its employees. Contributions made to this plan by OTP totaled \$2,229,000 for 2016 and \$1,985,000 for 2015.

Employee Stock Ownership Plan

OTP has a stock ownership plan for the benefit of all its employees. Contributions made by OTP were \$647,000 for 2016 and \$674,000 for 2015.

10. Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

Short-Term Debt—The carrying amount approximates fair value because the debt obligations are short-term and the balance outstanding as of December 31, 2016 and 2015 under the OTP Credit Agreement was subject to a variable interest rate of LIBOR plus 1.25%, which approximates a market rate.

Long-Term Debt including Current Maturities—The fair value of OTP's long-term debt is estimated based on the current market indications of rates available to OTP for the issuance of debt. The fair value measurements of OTP's long-term debt issues fall into level 2 of the fair value hierarchy set forth in ASC 820.

<i>(in thousands)</i>	December 31, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2016	2016/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Cash and Short-Term Investments	\$ 22	\$ 22	\$ 28	\$ 28
Short-Term Debt	(42,883)	(42,883)	(21,006)	(21,006)
Long-Term Debt including Current Maturities	(445,000)	(495,429)	(445,000)	(506,052)

11. Property, Plant and Equipment

<i>(in thousands)</i>	December 31, 2016	December 31, 2015	Service Life Range <i>(years)</i>	
			Low	High
Electric Plant				
Production	\$ 891,330	\$ 879,121	9	82
Transmission	410,679	391,941	42	70
Distribution	466,285	451,820	5	68
General	92,063	97,881	5	50
Electric Plant in Service	1,860,357	1,820,763		
Construction Work in Progress	149,997	64,117		
Total Plant	2,011,234	1,885,545		
Less Accumulated Depreciation and Amortization	703,061	666,949		
Net Plant	\$ 1,307,293	\$ 1,217,931		

12. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2016 and 2015) to net income before total income tax expense for the following reasons:

<i>(in thousands)</i>	2016	2015
Tax Computed at Federal Statutory Rate	\$ 23,168	\$ 22,553
Increases (Decreases) in Tax from:		
State Income Taxes Net of Federal Income Tax Benefit	2,499	3,828
Differences Reversing in Excess of Federal Rates	77	(1,143)
Federal Production Tax Credit	(7,175)	(6,962)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(850)	(850)
Dividend Received/Paid Deduction	(537)	(560)
Investment Tax Credit Amortization	(350)	(571)
Allowance for Funds Used During Construction - Equity	(280)	(426)
Permanent and Other Differences	(186)	198
Total Income Tax Expense	\$ 16,366	\$ 16,067
Overall Effective Federal and State Income Tax Rate	24.7%	24.9%
Income Tax Expense Includes the Following:		
Current Federal Income Taxes	\$ (57)	\$ 231
Current State Income Taxes	604	--
Deferred Federal Income Taxes	20,953	18,331
Deferred State Income Taxes	3,241	5,888
Federal Production Tax Credit	(7,175)	(6,962)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(850)	(850)
Investment Tax Credit Amortization	(350)	(571)
Total	\$ 16,366	\$ 16,067

OTP's deferred tax assets and liabilities were composed of the following on December 31:

<i>(in thousands)</i>	2016	2015
Deferred Tax Assets		
Federal Production Tax Credits (PTCs)	33,113	25,938

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

North Dakota Wind Tax Credits	40,869	41,326
Benefit Liabilities	27,238	26,129
Net Operating Loss Carryforward	9,035	28,423
Differences Related to Property	8,255	8,453
Other	6,467	5,822
Vacation Accrual	1,727	1,661
Investment Tax Credits	818	1,109
Total Deferred Tax Assets	\$ 127,522	\$ 138,861
Deferred Tax Liabilities		
Differences Related to Property	\$(323,012)	\$(319,556)
Renewable Resource Rider Accrued Revenue	(954)	(732)
Excess Tax over Book Pension	(15,509)	(13,775)
Other	(3,235)	(6,863)
North Dakota Wind Tax Credits	(11,543)	(11,543)
Regulatory Asset	(3,624)	(1,455)
AQCS Section 169	(2,645)	0
Impact of State Net Operating Losses on Federal Taxes	(894)	(1,481)
Total Deferred Tax Liabilities	\$(361,416)	\$(355,405)
Deferred Income Taxes	\$(233,894)	\$(216,544)

Federal PTCs are earned as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP's kwh generation from its wind turbines eligible for PTCs increased 3.6% in 2016 compared with 2015. North Dakota wind energy credits are based on dollars invested in qualifying facilities and are being recognized on a straight-line basis over 25 years.

Schedule of expiration of tax credits and tax net operating losses available as of December 31, 2016:

<i>(in thousands)</i>	Amount	2017	2027-2043
United States			
Federal Net Operating Losses	\$ 6,497	\$ --	\$ 6,497
Federal Tax Credits	33,113	--	33,113
State Net Operating Losses	2,538	--	2,538
State Tax Credits	33,350	389	32,961

The carryforward period on a portion of the North Dakota wind tax credits from the Langdon wind project is five years. OTP has adjusted its deferred tax assets and deferred tax credits by \$0.4 million for potential unused North Dakota wind tax credits related to the Langdon wind project.

The following table summarizes the activity related to OTP's unrecognized tax benefits:

<i>(in thousands)</i>	2016	2015
Balance on January 1	\$ 468	\$ 222
Increases Related to Tax Positions for Prior Years	40	236
Increases Related to Tax Positions for Current Year	--	10
Uncertain Positions Resolved During Year	(97)	--
Balance on December 31	\$ 411	\$ 468

The balance of unrecognized tax benefits as of December 31, 2016 would reduce the OTP's effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2016 is not expected to change significantly within the next 12 months. There was no amount accrued for interest on tax uncertainties as of December 31, 2016.

Otter Tail Corporation and its subsidiaries, including OTP, file a consolidated U.S. federal income tax return and various state income tax returns. As of December 31, 2016, with limited exceptions, Otter Tail Corporation is no longer subject to examinations by taxing

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

authorities for tax years prior to 2013 for federal and Minnesota and North Dakota state income taxes.

13. Asset Retirement Obligations (AROs)

OTP's AROs are related to its coal-fired generation plants and its 92 wind turbines located in North Dakota. The AROs include items such as site restoration, closure of ash pits, and removal of certain structures, generators, asbestos and storage tanks. OTP has legal obligations associated with the retirement of a variety of other long-lived tangible assets used in electric operations where the estimated settlement costs are individually and collectively immaterial. OTP has no assets legally restricted for the settlement of any of its AROs. OTP recorded no new AROs in 2016.

On December 19, 2014, the EPA's rule regulating coal combustion residuals (CCR) went into effect. The final rule regulates CCR as a non-hazardous solid waste under Subtitle D of the Resource Conservation and Recovery Act. In the second quarter of 2015, subsequent to publication of the CCR rule, OTP completed an assessment of its ash handling and storage facilities at Hoot Lake Plant, Coyote Station and Big Stone Plant and determined that it had no immediate obligation under the rules to close or modify any existing ash handling facilities or storage sites but has discontinued the use of one pit at Coyote Station to avoid the potential for future obligations related to this site under the CCR rule. Additionally, OTP identified a slag sluice pond and slag stockpile area at Big Stone Plant that will need to be reclaimed at a future date to comply with the CCR rule. OTP established an ARO liability of approximately \$0.5 million for its share of the estimated future costs to reclaim this site. Although identified as a new ARO resulting from the issuance of the CCR rule, the slag sluice pond and slag stockpile are currently in use, so the cost of the new ARO was capitalized. Therefore, the establishment of the ARO had no impact on operating expenses but resulted in an offsetting charge to the removal cost component of the accumulated provision for depreciation on OTP's balance sheet. Future reclamation costs, when incurred, will be charged against, and reduce, the accumulated ARO liability.

Reconciliations of carrying amounts of the present value of the OTP's legal AROs, capitalized asset retirement costs and related accumulated depreciation and a summary of settlement activity for the years ended December 31, 2016 and 2015 are presented in the following table:

<i>(in thousands)</i>	2016	2015
<u>Asset Retirement Obligations</u>		
Beginning Balance	\$ 8,084	\$ 7,721
New Obligations Recognized	--	451
Adjustments Due to Revisions in Cash Flow Estimates	(103)	(424)
Accrued Accretion	360	336
Settlements	--	--
Ending Balance	\$ 8,341	\$ 8,084
<u>Asset Retirement Costs Capitalized</u>		
Beginning Balance	\$ 3,086	\$ 3,059
New Obligations Recognized	--	451
Adjustments Due to Revisions in Cash Flow Estimates	(103)	(424)
Settlements	--	--
Ending Balance	\$ 2,983	\$ 3,086
<u>Accumulated Depreciation - Asset Retirement Costs Capitalized</u>		
Beginning Balance	\$ 673	\$ 527
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Depreciation Expense	122	146
Settlements	--	--
Ending Balance	\$ 795	\$ 673
<u>Settlements</u>		
Original Capitalized Asset Retirement Cost - Retired	\$ --	\$ --
Accumulated Depreciation	--	--
Asset Retirement Obligation	\$ --	\$ --
Settlement Cost	--	--

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Gain on Settlement – Deferred Under Regulatory Accounting	\$	--	\$	--
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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				(1,853,222)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				195,012
3	Preceding Quarter/Year to Date Changes in Fair Value				(17,900)
4	Total (lines 2 and 3)				177,112
5	Balance of Account 219 at End of Preceding Quarter/Year				(1,676,110)
6	Balance of Account 219 at Beginning of Current Year				(1,676,110)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				172,056
8	Current Quarter/Year to Date Changes in Fair Value				(137,845)
9	Total (lines 7 and 8)				34,211
10	Balance of Account 219 at End of Current Quarter/Year				(1,641,899)

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	1,635,803,103	1,635,803,103
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	222,877,093	222,877,093
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,858,680,196	1,858,680,196
9	Leased to Others		
10	Held for Future Use	29,656	29,656
11	Construction Work in Progress	149,997,025	149,997,025
12	Acquisition Adjustments	1,647,127	1,647,127
13	Total Utility Plant (8 thru 12)	2,010,354,004	2,010,354,004
14	Accum Prov for Depr, Amort, & Depl	703,060,660	703,060,660
15	Net Utility Plant (13 less 14)	1,307,293,344	1,307,293,344
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	696,458,493	696,458,493
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	4,955,039	4,955,039
22	Total In Service (18 thru 21)	701,413,532	701,413,532
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	1,647,128	1,647,128
33	Total Accum Prov (equals 14) (22,26,30,31,32)	703,060,660	703,060,660

Name of Respondent
Otter Tail Power Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2016

Year/Period of Report
End of 2016/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
					3
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					32
					33

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

Schedule Page: 200 Line No.: 8 Column: c

Per its FERC-approved tariff, the Company uses a 13-month average of gross electric plant in service for rate-making purposes, illustrated as follows for the current year:

	Gross Electric Plant in Service
December 31, 2015	1,819,086,230
January 31, 2016	1,819,999,290
February 29, 2016	1,821,645,185
March 31, 2016	1,822,459,949
April 30, 2016	1,822,934,220
May 31, 2016	1,822,716,684
June 30, 2016	1,832,480,586
July 31, 2016	1,842,268,206
August 31, 2016	1,843,959,846
September 30, 2016	1,841,253,884
October 31, 2016	1,851,952,028
November 30, 2016	1,853,079,456
December 31, 2016	1,858,680,196
13-month average for rate-making	1,834,808,905

Schedule Page: 200 Line No.: 11 Column: c

Per its FERC-approved tariff, the Company uses a 13-month average of CWIP for rate-making purposes, illustrated as follows for the current year:

	Account 107 Balance	CWIP not in Rates	CWIP in Rate Base
December 31, 2015	64,117,181	26,405,843	37,711,338
January 31, 2016	69,778,488	28,239,475	41,539,013
February 29, 2016	75,738,674	29,970,883	45,767,791
March 31, 2016	86,434,254	37,125,456	49,308,798
April 30, 2016	96,063,090	40,828,077	55,235,013
May 31, 2016	107,690,828	44,208,725	63,482,103
June 30, 2016	112,636,028	40,884,399	71,751,629
July 31, 2016	115,497,257	35,300,639	80,196,618
August 31, 2016	126,435,058	38,170,971	88,264,087
September 30, 2016	139,675,340	45,278,486	94,396,854
October 31, 2016	140,793,714	41,407,045	99,386,669
November 30, 2016	149,200,340	45,743,170	103,457,170
December 31, 2016	149,997,025	40,502,059	109,494,966
13-month average for rate-making			72,307,081

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

Otter Tail Power Company

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2016

Year/Period of Report

End of 2016/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance End of Year (f)	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)		
			1
			2
			3
			4
			5
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			22

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 202 Line No.: 2 Column: b
Not applicable.

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	1,301,974	
4	(303) Miscellaneous Intangible Plant	8,972,050	298,788
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	10,274,024	298,788
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,654,157	
9	(311) Structures and Improvements	124,334,314	1,328,567
10	(312) Boiler Plant Equipment	322,129,579	13,841,360
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	65,472,261	779,348
13	(315) Accessory Electric Equipment	36,595,821	80,420
14	(316) Misc. Power Plant Equipment	6,238,028	241,384
15	(317) Asset Retirement Costs for Steam Production	2,861,085	-102,933
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	559,285,245	16,168,146
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	299,623	
28	(331) Structures and Improvements	351,711	
29	(332) Reservoirs, Dams, and Waterways	4,277,057	
30	(333) Water Wheels, Turbines, and Generators	1,373,864	
31	(334) Accessory Electric Equipment	592,400	
32	(335) Misc. Power PLant Equipment	442,624	
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)	7,337,279	
36	D. Other Production Plant		
37	(340) Land and Land Rights	126,762	
38	(341) Structures and Improvements	12,946,210	
39	(342) Fuel Holders, Products, and Accessories	1,748,265	
40	(343) Prime Movers	31,897,512	886,326
41	(344) Generators	241,512,941	976,678
42	(345) Accessory Electric Equipment	20,546,282	19,516
43	(346) Misc. Power Plant Equipment	605,668	24,173
44	(347) Asset Retirement Costs for Other Production	224,652	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	309,608,292	1,906,693
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	876,230,816	18,074,839

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	11,008,968	3,424,658
49	(352) Structures and Improvements		
50	(353) Station Equipment	85,468,069	9,723,712
51	(354) Towers and Fixtures	85,885,043	-4,778,625
52	(355) Poles and Fixtures	107,218,330	5,604,070
53	(356) Overhead Conductors and Devices	102,215,588	5,231,832
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices	77,461	
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	391,873,459	19,205,647
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	1,244,390	53,885
61	(361) Structures and Improvements		
62	(362) Station Equipment	75,495,957	3,126,434
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	69,428,759	1,526,674
65	(365) Overhead Conductors and Devices	49,145,268	868,414
66	(366) Underground Conduit		
67	(367) Underground Conductors and Devices	71,676,281	3,156,138
68	(368) Line Transformers	89,762,014	4,543,501
69	(369) Services	52,446,423	1,588,041
70	(370) Meters	32,960,850	1,332,990
71	(371) Installations on Customer Premises	4,482,178	531,616
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	5,156,979	409,496
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	451,799,099	17,137,189
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	1,521,896	
87	(390) Structures and Improvements	30,412,560	282,861
88	(391) Office Furniture and Equipment	9,481,889	154,485
89	(392) Transportation Equipment	33,429,019	1,296,847
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	4,545,561	241,148
92	(395) Laboratory Equipment		
93	(396) Power Operated Equipment	605,062	79,588
94	(397) Communication Equipment	8,912,846	278,050
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	88,908,833	2,332,979
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	88,908,833	2,332,979
100	TOTAL (Accounts 101 and 106)	1,819,086,231	57,049,442
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)	1,819,086,231	57,049,442

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
			1,301,974		3
2,063,277			7,207,561		4
2,063,277			8,509,535		5
					6
					7
			1,654,157		8
179,041		-35,353	125,448,487		9
3,929,420		37,023	332,078,542		10
					11
351,141		-1,670	65,898,798		12
			36,676,241		13
45,068			6,434,344		14
			2,758,152		15
4,504,670			570,948,721		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			299,623		27
			351,711		28
			4,277,057		29
			1,373,864		30
			592,400		31
			442,624		32
					33
					34
			7,337,279		35
					36
			126,762		37
			12,946,210		38
			1,748,265		39
457,680			32,326,158		40
888,263			241,601,356		41
14,046			20,551,752		42
1,570			628,271		43
			224,652		44
1,361,559			310,153,426		45
5,866,229			888,439,426		46

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
			14,433,626	48
				49
52,512		-2,150	95,137,119	50
			81,106,418	51
126,649		-10,036	112,685,715	52
272,799		-2,772	107,171,849	53
				54
			77,461	55
				56
				57
451,960		-14,958	410,612,188	58
				59
		8,306	1,306,581	60
				61
507,888		9,195	78,123,698	62
				63
107,218		1,597	70,849,812	64
163,093		-7,895	49,842,694	65
				66
154,495		21,166	74,699,090	67
574,676		-17,411	93,713,428	68
55,299			53,979,165	69
795,706			33,498,134	70
226,928			4,786,866	71
				72
102,472			5,464,003	73
				74
2,687,775		14,958	466,263,471	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			1,521,896	86
121,165			30,574,256	87
3,742,246			5,894,128	88
1,749,294			32,976,572	89
				90
172,226			4,614,483	91
				92
68,603			616,047	93
532,702			8,658,194	94
				95
6,386,236			84,855,576	96
				97
				98
6,386,236			84,855,576	99
17,455,477			1,858,680,196	100
				101
				102
				103
17,455,477			1,858,680,196	104

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

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

Per its FERC-approved tariff, the Company uses a 13-month average of intangible electric plant in service for rate-making purposes, illustrated as follows for the current year:

	Intangible Electric Plant in Service
December 31, 2015	10,274,024
January 31, 2016	10,293,413
February 29, 2016	10,551,340
March 31, 2016	10,551,340
April 30, 2016	10,551,340
May 31, 2016	10,551,340
June 30, 2016	10,572,813
July 31, 2016	10,572,813
August 31, 2016	10,572,813
September 30, 2016	9,680,978
October 31, 2016	9,680,978
November 30, 2016	9,063,264
December 31, 2016	8,509,535
13-month average for rate-making	10,109,692

Schedule Page: 204 Line No.: 46 Column: g

Per its FERC-approved tariff, the Company uses a 13-month average of production plant in service for rate-making purposes, illustrated as follows for the current year:

	Production Plant in Service
December 31, 2015	876,230,816
January 31, 2016	876,255,066
February 29, 2016	876,456,516
March 31, 2016	876,290,049
April 30, 2016	876,348,402
May 31, 2016	876,306,877
June 30, 2016	876,627,965
July 31, 2016	885,533,927
August 31, 2016	885,740,049
September 30, 2016	882,182,797
October 31, 2016	888,736,830
November 30, 2016	890,116,776
December 31, 2016	888,439,426
13-month average for rate-making	881,174,269

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

Per its FERC-approved tariff, the Company uses a 13-month average of electric transmission plant in service for rate-making purposes, illustrated as follows for the current year:

	Electric Transmission Plant in Service
December 31, 2015	391,873,459
January 31, 2016	392,522,658
February 29, 2016	393,240,395
March 31, 2016	393,552,872
April 30, 2016	393,423,729
May 31, 2016	394,795,933

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

June 30, 2016	403,218,702
July 31, 2016	403,420,903
August 31, 2016	404,416,213
September 30, 2016	404,830,163
October 31, 2016	406,542,387
November 30, 2016	406,586,045
December 31, 2016	410,612,188
13-month average for rate-making	399,925,819

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

Per its FERC-approved tariff, the Company uses a 13-month average of distribution plant in service for rate-making purposes, illustrated as follows for the current year:

	Distribution Plant in Service
December 31, 2015	451,799,099
January 31, 2016	452,130,838
February 29, 2016	452,892,023
March 31, 2016	454,009,392
April 30, 2016	454,718,336
May 31, 2016	455,724,557
June 30, 2016	456,757,508
July 31, 2016	457,423,802
August 31, 2016	458,237,915
September 30, 2016	459,525,241
October 31, 2016	461,539,208
November 30, 2016	462,448,982
December 31, 2016	466,263,471
13-month average for rate-making	457,190,029

Schedule Page: 204 Line No.: 99 Column: g

Per its FERC-approved tariff, the Company uses a 13-month average of general plant in service for rate-making purposes, illustrated as follows for the current year:

	General Plant in Service
December 31, 2015	88,908,833
January 31, 2016	88,797,315
February 29, 2016	88,504,911
March 31, 2016	88,056,296
April 30, 2016	87,892,413
May 31, 2016	85,337,978
June 30, 2016	85,303,599
July 31, 2016	85,316,761
August 31, 2016	84,992,857
September 30, 2016	85,034,705
October 31, 2016	85,452,625
November 30, 2016	84,864,389
December 31, 2016	84,855,576
13-month average for rate-making	86,409,097

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	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					
41					
42					
43					
44					
45					
46					
47	TOTAL				

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	Various			29,656
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Various			
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			29,656

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

Schedule Page: 214 Line No.: 2 Column: d

Per its FERC-approved tariff, the Company uses a 13-month average of electric plant held for future use for rate-making purposes, illustrated as follows for the current year:

	Transmission	Distribution	Total
December 31, 2015	9,037	20,619	29,656
January 31, 2016	9,037	20,619	29,656
February 29, 2016	9,037	20,619	29,656
March 31, 2016	9,037	20,619	29,656
April 30, 2016	9,037	20,619	29,656
May 31, 2016	9,037	20,619	29,656
June 30, 2016	9,037	20,619	29,656
July 31, 2016	9,037	20,619	29,656
August 31, 2016	9,037	20,619	29,656
September 30, 2016	9,037	20,619	29,656
October 31, 2016	9,037	20,619	29,656
November 30, 2016	9,037	20,619	29,656
December 31, 2016	9,037	20,619	29,656
13-month average for rate-making			29,656

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	Big Stone, SD - Brookings Sub, SD - Construct Transmission Facilities	45,049,709
2	Big Stone, SD - Ellendale Sub, ND - Construct Transmission Facilities	8,380,831
3	Big Stone, SD - Big Stone South, SD - Construct Transmission Facilities	2,233,973
4	Big Stone, SD - Big Stone Plant Sub, SD - Construct Transmission Facilities	1,955,881
5	Big Stone, SD - Big Stone South Sub, SD - Construct Transmission Facilities	13,012,361
6	Buffalo, ND - Buffalo Sub, ND - Construct Transmission Facilities	4,350,052
7	System Wide - Substation Security CIP Version 5 - Construct Transmission Facilities	1,135,549
8	System Wide - New Natural Gas Generation - Construct Generating Plant	2,156,155
9	Big Stone, SD - Ellendale, ND CMA - Construct Transmission Facilities	38,862,240
10	Big Stone, SD - Ellendale, ND RETENTION - Construct Transmission Facilities	1,919,671
11	System Wide - CISone - Purchase Intangible Plant	4,530,829
12	Fergus Falls, MN - Hoot Lake Plant - Construct Generating Plant	1,741,162
13	System Wide - Storm Work Order - Construct Distribution Plant	1,566,077
14	Rugby, ND - 41.6 KV Breaker Station - Construct Transmission Facilities	1,636,566
15	Merricourt, ND - Wind Project - Construct Generating Plant	3,472,212
16	Total Projects under \$1,000,000	17,993,757
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	149,997,025

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	660,113,917	660,113,917		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	50,100,398	50,100,398		
4	(403.1) Depreciation Expense for Asset Retirement Costs	121,347	121,347		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,817,963	1,817,963		
7	Other Clearing Accounts	-80,214	-80,214		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	51,959,494	51,959,494		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	15,392,201	15,392,201		
13	Cost of Removal	3,889,270	3,889,270		
14	Salvage (Credit)	6,310,383	6,310,383		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	12,971,088	12,971,088		
16	Other Debit or Cr. Items (Describe, details in footnote):	-2,643,830	-2,643,830		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	696,458,493	696,458,493		

Section B. Balances at End of Year According to Functional Classification

20	Steam Production	232,767,972	232,767,972		
21	Nuclear Production				
22	Hydraulic Production-Conventional	4,225,938	4,225,938		
23	Hydraulic Production-Pumped Storage				
24	Other Production	103,705,536	103,705,536		
25	Transmission	115,585,011	115,585,011		
26	Distribution	203,012,975	203,012,975		
27	Regional Transmission and Market Operation				
28	General	37,161,061	37,161,061		
29	TOTAL (Enter Total of lines 20 thru 28)	696,458,493	696,458,493		

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

Schedule Page: 219 Line No.: 7 Column: c

Inventory costs cleared to construction or utility operating expense.

Schedule Page: 219 Line No.: 16 Column: c

The net activity during the year for construction/removal not classified.

Schedule Page: 219 Line No.: 29 Column: c

Per its FERC-approved tariff, the Company uses a 13-month average of accumulated depreciation of production, transmission, distribution and general plant for rate-making purposes, illustrated as follows for the current year:

	Production *	Transmission	Distribution	General	Total
December 31, 2015	318,357,775	108,159,556	194,662,831	38,933,755	660,113,917
January 31, 2016	320,666,140	108,629,583	195,280,791	39,225,327	663,801,841
February 29, 2016	323,607,976	109,095,470	195,835,263	39,602,628	668,141,336
March 31, 2016	326,019,457	109,619,996	196,471,347	39,589,849	671,700,649
April 30, 2016	328,455,738	110,079,288	197,132,024	39,809,725	675,476,775
May 31, 2016	331,491,008	110,613,380	197,734,817	37,635,452	677,474,657
June 30, 2016	333,945,000	111,146,714	198,450,201	37,820,134	681,362,049
July 31, 2016	336,408,233	111,700,787	199,123,079	38,093,131	685,325,230
August 31, 2016	338,827,525	112,131,667	199,841,048	38,122,081	688,922,321
September 30, 2016	340,925,575	113,404,583	200,659,884	37,871,158	692,861,200
October 31, 2016	343,280,853	113,924,696	201,583,607	38,070,054	696,859,210
November 30, 2016	344,118,565	114,538,656	202,420,792	37,828,087	698,906,099
December 31, 2016	340,699,445	115,585,011	203,012,975	37,161,061	696,458,493
13-month average for rate-making	332,831,022	111,433,030	198,631,435	38,443,265	681,338,752

* Production is a total of lines 20 through 24 on page 219

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	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				
41				
42	Total Cost of Account 123.1 \$	0	TOTAL	

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 from investments, including such revenues from 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
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
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				41
				42

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of <u>2016/Q4</u>
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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)	12,309,141	9,830,796	Production
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)	5,955,359	6,454,839	Production
8	Transmission Plant (Estimated)	5,153,618	5,284,837	Various
9	Distribution Plant (Estimated)	7,723,909	6,764,528	Various
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	285,207	318,305	Fleet Service
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	19,118,093	18,822,509	
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)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	31,427,234	28,653,305	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

Schedule Page: 227 Line No.: 7 Column: c

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Production Plant
December 31, 2015	5,955,359
January 31, 2016	5,945,850
February 29, 2016	3,039,856
March 31, 2016	6,147,055
April 30, 2016	6,214,414
May 31, 2016	6,256,675
June 30, 2016	6,287,235
July 31, 2016	6,340,005
August 31, 2016	6,345,929
September 30, 2016	6,319,741
October 31, 2016	6,406,578
November 30, 2016	6,485,840
December 31, 2016	6,454,839
13-month average for rate-making	6,015,337

Schedule Page: 227 Line No.: 8 Column: c

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Transmission Plant
December 31, 2015	5,153,618
January 31, 2016	5,209,680
February 29, 2016	5,201,144
March 31, 2016	5,182,832
April 30, 2016	5,240,302
May 31, 2016	5,099,334
June 30, 2016	5,212,263
July 31, 2016	5,206,062
August 31, 2016	5,409,320
September 30, 2016	5,442,732
October 31, 2016	5,502,823
November 30, 2016	5,558,637
December 31, 2016	5,284,837
13-month average for rate-making	5,284,891

Schedule Page: 227 Line No.: 9 Column: c

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

	Distribution Plant
December 31, 2015	7,723,909

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

January 31, 2016	7,738,362
February 29, 2016	7,527,793
March 31, 2016	7,601,070
April 30, 2016	7,283,891
May 31, 2016	7,618,301
June 30, 2016	7,444,499
July 31, 2016	7,391,376
August 31, 2016	7,626,364
September 30, 2016	7,258,078
October 31, 2016	6,842,243
November 30, 2016	6,800,571
December 31, 2016	6,764,528
13-month average for rate-making	7,355,460

Schedule Page: 227 Line No.: 11 Column: b

Consists of parts inventory at the Fleet Service Department.

Schedule Page: 227 Line No.: 11 Column: c

Per its FERC-approved tariff, the Company uses a 13-month average of materials and supplies for rate-making purposes, illustrated as follows for the current year:

Assigned to - Other	
December 31, 2015	285,207
January 31, 2016	282,292
February 29, 2016	298,035
March 31, 2016	301,060
April 30, 2016	300,740
May 31, 2016	314,132
June 30, 2016	328,563
July 31, 2016	327,409
August 31, 2016	319,396
September 30, 2016	314,696
October 31, 2016	316,275
November 30, 2016	304,858
December 31, 2016	318,305
13-month average for rate-making	308,536

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		2017	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	44,886.00	59,417	14,054.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)			1,256.00	
5	Returned by EPA	26.00			
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	6,463.00	28,032		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	38,449.00	31,385	15,310.00	
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	202.96		202.96	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	202.96			
40	Balance-End of Year			202.96	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	202.96	12		
45	Gains	202.96	12		
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/transfersors 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.

2018		2019		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
14,054.00		14,054.00		365,404.00		452,452.00	59,417	1
								2
								3
1,256.00				14,054.00		16,566.00		4
						26.00		5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						6,463.00	28,032	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
15,310.00		14,054.00		379,458.00		462,581.00	31,385	29
								30
								31
								32
								33
								34
								35
								36
202.96		202.97		9,945.16		10,757.01		36
				405.92		405.92		37
								38
				202.96		405.92		39
202.96		202.97		10,148.12		10,757.01		40
								41
								42
								43
				202.96	4	405.92		16 44
				202.96	4	405.92		16 45
								46

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 228 Line No.: 1 Column: b

Includes 1,256 of initial allocations from EPA and 616 of rollover allowances for Cross State Air Pollution Rule.

Schedule Page: 228 Line No.: 4 Column: d

Includes 1,256 of initial allocations from EPA for Cross State Air Pollution Rule.

Schedule Page: 228 Line No.: 4 Column: f

Includes 1,256 of initial allocations from EPA for Cross State Air Pollution Rule.

Schedule Page: 228 Line No.: 18 Column: c

Includes 940 of emission charges for Cross State Air Pollution Rule.

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		2017	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	1,327.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)			876.00	
5	Returned by EPA	18.00			
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	358.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	987.00		876.00	
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/transfersors 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.

2018		2019		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						1,327.00		1
								2
								3
876.00						1,752.00		4
						18.00		5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						358.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
876.00						2,739.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 229 Line No.: 1 Column: b

Includes 876 of initial allocations from EPA and 451 rollover allowances for Cross State Air Pollution Rule.

Schedule Page: 229 Line No.: 4 Column: d

Includes 876 of initial allocations from EPA for Cross State Air Pollution Rule.

Schedule Page: 229 Line No.: 4 Column: f

Includes 876 of initial allocations from EPA for Cross State Air Pollution Rule.

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of <u>2016/Q4</u>
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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					

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	BSII cancelled project - MN	468,114		See note	-515,040	-46,926
22	- Generation					
23	MPUC order issued 04-25-2011.					
24	Remaining recovery period: 10 mos					
25						
26	BSII cancelled project - MN	3,093,678		See note	-181,572	2,912,106
27	-Transmission					
28	MPUC order issued 04-25-2011.					
29	Remaining recovery period: 52 mos					
30						
31	BSII cancelled project - SD	510,021		407	-100,331	409,690
32	-Generation					
33	SDPUC order issued 02-11-2010					
34	Remaining recovery period: 25 mos					
35						
36	BSII cancelled project - SD	232,957				232,957
37	-Transmission					
38	SDPUC order issued 04-30-2013					
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	4,304,770			-796,943	3,507,827

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 230 Line No.: 21 Column: a

Otter Tail Power Company will continue to collect from customers through October 2017 (10 months). However, at some point beyond that, the Company will begin refunding these amounts to customers because of overcollecting on these costs.

Schedule Page: 230 Line No.: 21 Column: d

Accounts 407 and 431 were used.

Schedule Page: 230 Line No.: 26 Column: d

Accounts 407 and 419 were used.

Schedule Page: 230 Line No.: 36 Column: b

This is the South Dakota transmission balance that will be deferred until the next rate case.

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	Bitter Root & Astoria	3,440	456	3,946	456
3	Red Lake Falls Wind	1,260	456	1,452	456
4	MPC LaPort	994	456		456
5	MPC Lake Park	597	456		456
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22	Courteney Wind	6,113	456	6,794	456
23	Dakota Range	11,538	456	11,400	456
24	Red Lake Falls Generation	6,894	456	6,894	456
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Deferred Income Tax Adjustments					
2	Due to ASC 740 on:					
3	Property/Non Property Related Items	1,455,024		282	441,048	1,013,976
4						
5	Asset Retirement Obligation Capitalized					
6	Hoot Lake Plant	1,927,512	107,216			2,034,728
7	Big Stone Plant	511,027	89,086			600,113
8	Coyote Station	2,171,252	208,453			2,379,705
9	Wind Generation - Langdon	437,784	26,339	407.4	2,331	461,792
10	Wind Generation - Ashtabula	321,715	26,850	407.4	1,982	346,583
11	Wind Generation - Luverne	302,129	27,884			330,013
12						
13	Derivatives-Marked to Market Losses	14,593,404		253	4,062,921	10,530,483
14						
15	MISO Schedules 26 & 26A Accrual	1,053,454	1,493,252	See note	2,213,789	332,917
16						
17	MN Renewable Resource Rider	68,361		407.3	34,180	34,181
18	ND Renewable Resource Rider	1,265,774	4,023,698	See note	3,488,353	1,801,119
19						
20	ESSRP	3,010,590	249,179	228.3	311,419	2,948,350
21						
22	Pension	102,303,455	3,003,733	228.3	7,127,539	98,179,649
23						
24	MN Transmission Revenue Rider	576,066	182,909	See note	758,975	
25	ND Transmission Revenue Rider		666,350	See note	98,184	568,166
26	SD Transmission Revenue Rider	32,850	537,010	See note	355,701	214,159
27						
28	Post Retirement Medical Benefits	1,417,899	12,676,402	228.3	512,122	13,582,179
29						
30	Conservation Improvement Program - MN	8,493,231	6,316,463	186	4,921,840	9,887,854
31	Energy Efficiency Program - SD	183,356	156,038	186	233,494	105,900
32						
33	Rate Case Expense Deferral	290,748	1,439,306	407.4	648,465	1,081,589
34						
35	ND Environmental Cost Recovery Rider		112,527			112,527
36						
37						
38	See footnote 3 in Notes to Financial Statements					
39	for amortization periods.					
40						
41						
42						
43						
44	TOTAL	140,415,631	31,342,695		25,212,343	146,545,983

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 232 Line No.: 15 Column: d

Accounts 440, 442, 444, and 445 were debited.

Schedule Page: 232 Line No.: 18 Column: d

Accounts 440, 442, 444, and 445 were debited.

Schedule Page: 232 Line No.: 24 Column: d

Accounts 440, 442, 444, and 445 were debited.

Schedule Page: 232 Line No.: 25 Column: d

Accounts 440, 442, 444, and 445 were debited.

Schedule Page: 232 Line No.: 26 Column: d

Accounts 440, 442, 444, and 445 were debited.

Name of Respondent
Otter Tail Power Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2016

Year/Period of Report
End of 2016/Q4

MISCELLANEOUS DEFERRED 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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Conservation Improvement					
2	Programs - MN		7,770,781	182.3	7,770,781	
3						
4	Energy Efficiency Program - SD		362,330	182.3	362,330	
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47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL					

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 Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Property Insurance Reserve		
3	Workman's Compensation Reserve	226,283	303,140
4	Medical Insurance Reserve		
5	Injuries and Damages Reserve		
6	See Note Below	138,634,382	127,218,951
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	138,860,665	127,522,091
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)	138,860,665	127,522,091

Notes

	Balance at Beginning of Year	Balance at End of Year
	-----	-----
Post Retirement Benefits	20,750,054	21,385,284
Executive Supplemental Pension	4,320,986	4,436,130
Reserve for Bad Debts	328,485	339,929
Accrued Vacation Pay	1,661,373	1,726,790
Capitalized Int. on Construction	5,453,637	5,609,720
Post Employment Benefits	219,208	457,711
Incentive Plans	331,328	566,197
Nonqualified Retirement Savings	277,316	311,250
Federal NOL Carryforward	24,207,827	6,496,988
Reserve for Loan Pools	6,933	4,683
Property Damage Reserves	(110,582)	(304,432)
Capitalized A & G	2,855,688	2,541,368
Customer Rebates Capitalized	125,956	120,832
Stock Incentives	43,862	11,197
CIAC Capitalized	124,465	101,838
BSII Discount	266,851	213,216
Unicap Adjustment	39,773	35,983
Medicare Part D	477,347	465,274
Research Credit Carryforward	329,514	374,580
Charitable Contributions	237,330	0
Severance Settlement	(333)	0
Flow-Through Items	137,860	113,284
State NOL Carryforward	4,214,577	2,538,110
Wind Energy Income Tax Credits-ND	41,325,966	40,868,577
ASC 740 Unamortized ITC	1,109,433	817,529
ASC 740 Recognition of Regulatory Assets (Liab.)	3,961,768	4,874,172
Wind Production Tax Credit Deferral (Asset)	25,937,759	33,112,740
	-----	-----
	138,634,382	127,218,951

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 (Par)			
2	Common Stock	50,000,000	5.00	
3				
4				
5	TOTAL COMMON	50,000,000		
6				
7	Cumulative Preferred	1,500,000		
8	Cumulative Preference	1,000,000		
9	TOTAL PREFERRED	2,500,000		
10				
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Name of Respondent

Otter Tail Power Company

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2016

Year/Period of Report

End of 2016/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.
Shares (e)	Amount (f)	AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
		Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
100	500					2
						3
						4
100	500					5
						6
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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	Parent company investment in Otter Tail Power Company	339,988,966
2	Additional parent investment	37,000,000
3		
4		
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40	TOTAL	376,988,966

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of <u>2016/Q4</u>
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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	Common Shares	
2		
3	Not applicable	
4		
5		
6		
7		
8		
9		
10		
11		
12		
13	Cumulative Preferred Shares	
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

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 221 - Bonds		
2	2021 Series 4.63% Notes	140,000,000	891,854
3			
4	Senior Unsecured Notes 6.47%, Series D	50,000,000	665,975
5			
6	Senior Unsecured Notes 6.37%, Series C	42,000,000	540,768
7			
8	Senior Unsecured Notes 6.15%, Series B	30,000,000	386,988
9			
10	Senior Unsecured Notes 5.95%, Series A	33,000,000	424,856
11			
12	Senior Unsecured Notes 4.68%, Series A	60,000,000	195,814
13			
14	Senior Unsecured Notes 5.47%, Series B	90,000,000	294,168
15			
16			
17			
18			
19			
20			
21			
22	Account 222 - Reacquired Bonds - None		
23	Account 223 - Advances from associated companies - None		
24	Account 224 Other Long Term Debt - None		
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	445,000,000	3,400,423

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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
07/29/2011	12/01/2021	12/01/2011	11/30/2021	140,000,000	6,482,000	2
						3
08/20/2007	8/20/2037	8/20/2007	8/20/2037	50,000,000	3,235,000	4
&10/1/2007						5
08/20/2007	08/20/2027	8/20/2007	8/20/2027	42,000,000	2,675,400	6
&10/1/2007						7
10/01/2007	08/20/2022	10/01/2007	08/20/2022	30,000,000	1,845,000	8
						9
10/01/2007	08/20/2017	10/01/2007	08/20/2017	33,000,000	1,963,500	10
						11
02/27/2014	02/27/2029	02/27/2014	02/27/2029	60,000,000	2,808,000	12
						13
02/27/2014	02/27/2044	02/27/2014	02/27/2044	90,000,000	4,923,000	14
						15
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				445,000,000	23,931,900	33

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 16 Column: a

Instruction 9 - Unamortized debt expense remaining on bonds retired early is transferred to Account 189 and amortized over remaining life of the bonds.

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 filed, 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)	49,828,835
2		
3		
4	Taxable Income Not Reported on Books	
5	Interest capitalized on construction	904,482
6	Net gain from property retirements	4,735,136
7	Miscellaneous taxable items	6,000
8	Conservation improvement program	-5,254,838
9	Deductions Recorded on Books Not Deducted for Return	
10	Add back federal income taxes (includes deferreds & ITC adjustment)	16,366,170
11	Provision for reserves	8,665,673
12	Miscellaneous unallowed deductions	67,805,298
13		
14	Income Recorded on Books Not Included in Return	
15	Tax exempt interest	
16	Equity in earnings of subsidiaries	
17	Wind rider revenue	7,765,592
18	Miscellaneous income not taxable	
19	Deductions on Return Not Charged Against Book Income	
20	Excess tax depreciation over book depreciation	11,631,746
21	Removal costs	2,896,437
22	Charges to reserves	6,662,766
23	Leveraged ESOP deduction	1,644,809
24	Sec 481(a) Cap to Repair basis adjustments	
25	Miscellaneous other deductions	63,165,645
26		
27	Federal Tax Net Income	49,289,760
28	Show Computation of Tax:	
29	Federal tax (Line 27 x 35%)	17,251,416
30	Tax (credits) and adjustments	-6,000
31	Prior period adjustments	-56,770
32	Transfer net operating loss to deferred carryforward	-17,245,418
33	Total federal income tax	-56,772
34		
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Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2016	2016/Q4
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 44 Column: a

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME
FOR FEDERAL INCOME TAXES

Otter Tail Power Company is a member of an affiliated group which will file a consolidated Federal income tax return for the year 2016. The other members of the affiliated group and their respective federal income tax provisions are as follows:

1	Otter Tail Corporation-Corporate	(3,451,607)
2	Varistar Corporation	9,037
3	IMD, Inc.	16,485
4	BTD Manufacturing, Inc.	2,392,405
5	Northern Pipe Products, Inc.	2,904,142
6	Vinyltech Corporation	3,133,433
7	Otter Tail Energy Services Company	0
8	T. O. Plastics, Inc.	1,165,325
9	Shrco, Inc. (formerly Shoremaster, Inc.)	(6,190)
10	Otter Tail Assurance Limited	262,263
11	AEV, Inc.	(198)
12	ASI, Inc. (formerly Aviva Sports, Inc.)	(33,626)
13	Miller Welding & Iron Works, Inc.	(1,353,324)
	Total	5,038,143

The consolidated federal income tax liability is allocated on a separate return basis pursuant to the current tax sharing agreements between Otter Tail Corporation and the subsidiaries.

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 known, 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)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	FEDERAL					
2	Income			17,188,647	17,188,647	
3	Unemployment	662		36,642	36,736	
4	FICA			4,770,480	4,770,480	
5						
6	MINNESOTA					
7	Property	9,075,001		9,455,042	8,830,043	
8	Income			1,432,528	828,514	
9	Unemployment	654		29,654	29,069	
10						
11	NORTH DAKOTA					
12	Property	2,375,000		2,466,504	2,341,504	
13	Income			826,449	826,449	
14	Unemployment	894		23,557	23,536	
15	Coal Conversion	146,991		2,032,172	1,991,739	
16						
17	SOUTH DAKOTA					
18	Property	1,700,000		1,693,199	1,593,199	
19	Unemployment	427		7,986	8,341	
20						
21	OTHER STATES					
22	Income					
23	Railcar	10,604		17,014	20,490	
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40						
41	TOTAL	13,310,233		39,979,874	38,488,747	

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
		-173,056			17,361,703	2
568					36,642	3
					4,770,480	4
						5
						6
9,700,000		9,455,042				7
604,014		587,161			845,367	8
1,239					29,654	9
						10
						11
2,500,000		2,401,968			64,536	12
		-2,235			828,684	13
915					23,557	14
187,424		2,032,172				15
						16
						17
1,800,000		1,693,199				18
72					7,986	19
						20
						21
						22
7,128					17,014	23
						24
						25
						26
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						40
14,801,360		15,994,251			23,985,623	41

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 262 Line No.: 2 Column: I

Account 409.2: 116,284; Other: 17,245,419

Schedule Page: 262 Line No.: 3 Column: I

Account 184

Schedule Page: 262 Line No.: 4 Column: I

Account 184

Schedule Page: 262 Line No.: 8 Column: I

Account 409.2: 16,852; Other: 828,515

Schedule Page: 262 Line No.: 9 Column: I

Account 184

Schedule Page: 262 Line No.: 12 Column: I

Account 921: 56,688; Account 408.2: 7,848

Schedule Page: 262 Line No.: 13 Column: I

Account 409.2: 2,238; Other: 826,446

Schedule Page: 262 Line No.: 14 Column: I

Account 184

Schedule Page: 262 Line No.: 19 Column: I

Account 184

Schedule Page: 262 Line No.: 23 Column: I

Account 151

Name of Respondent
Otter Tail Power Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2016

Year/Period of Report
End of 2016/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%	23,846,173			411.4	1,306,824	
3	4%						
4	7%						
5	10%	659,872			411.4	349,907	
6							
7							
8	TOTAL	24,506,045				1,656,731	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
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48							

Name of Respondent
Otter Tail Power Company

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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
22,539,349	25 years		2
			3
			4
309,965	33.3 years		5
			6
			7
22,849,314			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
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			45
			46
			47
			48

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OTHER DEFERRED 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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Prepaid Electric Revenue	1,064,153	456	249,427	361,606	1,176,332
2	Payroll Clearing	1,274	184	1,248,617	1,247,343	
3	Discontinued Mark-to-Market	10,530,480	182.3	4,062,921		6,467,559
4	Forward Energy Contracts					
5	(Amortization thru Dec 2020)					
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						
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32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	11,595,907		5,560,965	1,608,949	7,643,891

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 relating to amortizable property.
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	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		2,645,124	
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)		2,645,124	
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)		2,645,124	
18	Classification of TOTAL			
19	Federal Income Tax		2,195,636	
20	State Income Tax		449,488	
21	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
						2,645,124	11
							12
							13
							14
						2,645,124	15
							16
						2,645,124	17
							18
						2,195,636	19
						449,488	20
							21

NOTES (Continued)

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization
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 282			
2	Electric	336,771,334	15,763,872	15,331,994
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	336,771,334	15,763,872	15,331,994
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	336,771,334	15,763,872	15,331,994
10	Classification of TOTAL			
11	Federal Income Tax	289,412,593	11,300,964	12,476,927
12	State Income Tax	47,358,740	4,462,908	2,855,067
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
-34	137,901			See note	322,102	337,387,379	2
							3
							4
-34	137,901				322,102	337,387,379	5
							6
							7
							8
-34	137,901				322,102	337,387,379	9
							10
	114,734				270,213	288,392,109	11
-34	23,167				51,890	48,995,270	12
							13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
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FOOTNOTE DATA			

Schedule Page: 274 Line No.: 2 Column: i

Acct 182.3 Adjustment due to ASC 740

Schedule Page: 274 Line No.: 2 Column: k

Amortization of Loss on Reacquired Debt (pre-holdco)	(602,232)
Big Stone II Deferred Costs	(1,497,866)
Retirements Method Change	195,983
South Dakota Flow Thru-Overheads	(17,596)
Prepaid Expenses	(294,759)
ADR Repair Allowance	(2,207,865)
Sec 172 & 174 R&D Deduction	(3,825,040)
Highway Powerline Relocation	(109,812)
AFUDC on Debt	(3,161,591)
Capitalized Overheads	4,338
Repairs Deduction - Basis Adjustments	(14,329,101)
Sec 481(a) Cap to Repair Basis Adjustments (PV)	4,566,578
Excess Tax Over Book Depreciation	(301,287,223)
North Dakota Investment Tax Credit - Federal Impacts	(11,542,931)
ASC 740 (SFAS 109) ADIT Credits - Property	(3,278,262)

Total	(337,387,379)
	=====

ACCUMULATED DEFERRED 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	Accum. Deferred Income Tax			
4	Other Utility Operations	17,005,249	16,555,804	15,997,968
5				
6	Accum. Deferred Income Tax			
7	Nonutility & Other	1,628,547		
8				
9	TOTAL Electric (Total of lines 3 thru 8)	18,633,796	16,555,804	15,997,968
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	18,633,796	16,555,804	15,997,968
20	Classification of TOTAL			
21	Federal Income Tax	14,552,398	12,929,552	12,493,900
22	State Income Tax	4,081,398	3,626,252	3,504,068
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				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
		Note		Note	125,716	17,688,801	4
							5
							6
2,067,567	806					3,695,308	7
							8
2,067,567	806				125,716	21,384,109	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
2,067,567	806				125,716	21,384,109	19
							20
1,614,704	629				98,180	16,700,305	21
452,863	177				27,536	4,683,804	22
							23

NOTES (Continued)

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FOOTNOTE DATA			

Schedule Page: 276 Line No.: 4 Column: i

Acct 228.3	Adjustment in Col. j due to ASC 715-60	(23,541)
Acct 182.3	Adjustment in Col. j due to ASC 740	149,257

	Total	125,716

Schedule Page: 276 Line No.: 7 Column: a

Deferred taxes related to CIP costs.

Schedule Page: 276 Line No.: 19 Column: k

Pensions	(15,508,976)
Conservation Improvement Program - MN & SD - Net (BTL)	(3,695,308)
Wind Rider Revenue	(954,771)
Transmission Rider Revenue	1,123,981
Environmental Rider Revenue	125,033
MN Rate Case Expenses	(63,878)
Deferred State NOL's - Federal Haircut	(894,160)
Regulatory Adjustments	1,093,859
ASC 740 (SFAS 109) ADIT Credits - Non-Property	(2,609,889)

Total	(21,384,109)
	=====

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 Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Deferred Income Tax Adjustments Due to	1,109,434	190	291,905		817,529
2	ASC 740					
3						
4	Minnesota Portion of Gain on Sale	100,371	407.4	5,575		94,796
5	of Wahpeton Division Office					
6						
7	Reclass SD EEP to Regulatory Liability				15,484	15,484
8						
9	MN Transmission Revenue Rider		See note	599,270	1,356,004	756,734
10	ND Transmission Revenue Rider	131,437	See note	369,523	2,401,579	2,163,493
11						
12	ND Renewable Resource Revenue Rider	68,359	See note	68,359		
13						
14	MN Future Rate Case Expense Accrual	1,278,937	407.4	504,100	144,396	919,233
15						
16	SD Environmental Revenue Rider	184,920	See note	152,748	252,730	284,902
17	ND Environmental Revenue Rider	320,870	See note	960,382	639,512	
18	MN Environmental Revenue Rider	777,137	See note	898,948	260,839	139,028
19						
20	MISO Schedule 26 and 26A Accrual		182.3	86,192	218,061	131,869
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31	See Footnote 3 in Notes to Financial					
32	Statements for amortization periods.					
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	3,971,465		3,937,002	5,288,605	5,323,068

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FOOTNOTE DATA			

Schedule Page: 278 Line No.: 9 Column: c

Offsetting accounts were 440, 442, 444, and 445.

Schedule Page: 278 Line No.: 10 Column: c

Offsetting accounts were 440, 442, 444, and 445.

Schedule Page: 278 Line No.: 12 Column: c

Offsetting accounts were 440, 442, 444, and 445.

Schedule Page: 278 Line No.: 16 Column: c

Offsetting accounts were 440, 442, 444, and 445.

Schedule Page: 278 Line No.: 17 Column: c

Offsetting accounts were 440, 442, 444, and 445.

Schedule Page: 278 Line No.: 18 Column: c

Offsetting accounts were 440, 442, 444, and 445.

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	115,782,375	116,279,070
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	136,091,872	138,431,230
5	Large (or Ind.) (See Instr. 4)	116,282,174	98,305,377
6	(444) Public Street and Highway Lighting	3,749,416	3,670,700
7	(445) Other Sales to Public Authorities	3,037,982	3,097,480
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	374,943,819	359,783,857
11	(447) Sales for Resale	4,583,862	2,498,622
12	TOTAL Sales of Electricity	379,527,681	362,282,479
13	(Less) (449.1) Provision for Rate Refunds	3,589,322	
14	TOTAL Revenues Net of Prov. for Refunds	375,938,359	362,282,479
15	Other Operating Revenues		
16	(450) Forfeited Discounts	673,301	690,605
17	(451) Miscellaneous Service Revenues	376,991	385,821
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	531,356	522,340
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	6,741,340	6,856,260
22	(456.1) Revenues from Transmission of Electricity of Others	36,517,370	28,798,406
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	44,840,358	37,253,432
27	TOTAL Electric Operating Revenues	420,778,717	399,535,911

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
1,220,946	1,272,912	103,439	103,039	2
				3
1,572,211	1,588,296	26,849	26,725	4
1,893,184	1,665,699	56	57	5
25,088	25,851	412	408	6
38,993	40,846	598	593	7
				8
				9
4,750,422	4,593,604	131,354	130,822	10
205,208	115,860			11
4,955,630	4,709,464	131,354	130,822	12
				13
4,955,630	4,709,464	131,354	130,822	14

Line 12, column (b) includes \$ 2,211,258 of unbilled revenues.
 Line 12, column (d) includes 27,270 MWH relating to unbilled revenues

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FOOTNOTE DATA			

Schedule Page: 300 Line No.: 4 Column: b

Small (or Commercial) includes all customers having a demand of less than 1000 kw.

Schedule Page: 300 Line No.: 5 Column: b

Large (or Industrial) includes all customers having a demand exceeding 1000 kw.

Schedule Page: 300 Line No.: 17 Column: b

Description of Revenue	Current Year	Prior Year
All others (under \$250,000 each)	\$ 376,991	\$ 385,821
	-----	-----
Total	\$ 376,991	\$ 385,821
	=====	=====

Schedule Page: 300 Line No.: 21 Column: b

Description of Revenue	Current Year	Prior Year
Sale of steam	\$ 1,605,959	\$ 1,115,569
Integrated transmission deficiency payments	1,700,564	1,621,282
Load control & dispatch	1,561,177	0
Wind generation development	336,154	3,009,517
All others (under \$250,000 each)	1,537,486	1,109,892
	-----	-----
Total	\$ 6,741,340	\$ 6,856,260
	=====	=====

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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					
18					
19					
20					
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23					
24					
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30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

SALES OF ELECTRICITY BY RATE SCHEDULES

- 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.
- 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.
- 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.
- 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).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- 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-440					
2	Residential Service 9.01	866,057	92,582,475	97,917	8,845	0.1069
3						
4	Residential Service (Ctrl'd Demand					
5	9.02	136,507	10,628,685	6,226	21,925	0.0779
6						
7	Water Heating Ctrl'd (Off-Peak)					
8	14.01	36,751	2,878,721	15,779	2,329	0.0783
9				-15,779		
10	Controlled Service					
11	14.04,14.05,14.06,14.07	171,739	8,841,690	13,524	12,699	0.0515
12				-13,524		
13	Fixed Time of Delivery Service					
14	14.07	5,128	207,840	419	12,239	0.0405
15				-419		
16	Outdoor lighting-energy only					
17	11.03	84	8,172	13	6,462	0.0973
18				-13		
19	Outdoor Lighting					
20	11.04	3,833	579,937	312	12,285	0.1513
21				-312		
22	Small power producer rider					
23	12.01		600	13		
24				-13		
25	Off-peak Electr Vehicle Rider					
26	14.12		19			
27						
28	Conservation Imp Prog Rev		-968,636			
29	Environmental Rider Rev		293,100			
30	Transmission Cost Recvy		-1,031,364			
31	Renewable Resource Rider		263,785			
32	Fuel Clause Adjustment Rec		1,259,572			
33	MN Rate Case Rev Reduction		-37,832			
34	SUBTOTAL Billed	1,220,099	115,506,764	104,143	11,716	0.0947
35	Unbilled Rev (See Instr. 6)	847	275,611			0.3254
36	TOTAL - 440	1,220,946	115,782,375	104,143	11,724	0.0948
37						
38	Column D Lines 9,12,15,18,21&24					
39	customers are also served					
40	under other residential service.					
41	TOTAL Billed	4,723,152	372,732,561	134,877	35,018	0.0789
42	Total Unbilled Rev.(See Instr. 6)	27,270	2,211,258	0	0	0.0811
43	TOTAL	4,750,422	374,943,819	134,877	35,220	0.0789

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	Commercial & Industrial-442					
2	General Service					
3	10.01,10.02	742,108	74,486,315	24,853	29,860	0.1004
4						
5	Farm Service					
6	9.03	72,700	6,764,992	2,817	25,808	0.0931
7						
8	Large General Service					
9	10.03	615,288	43,723,134	353	1,743,025	0.0711
10						
11	Real Time Pricing Rider					
12	14.02	45,797	1,641,675	2	22,898,500	0.0358
13						
14	Large Gen. Srv. (Time of Day)					
15	10.05	1,067,397	67,327,891	93	11,477,387	0.0631
16						
17	Large General Service Rider					
18	14.03	124,349	5,194,988	15	8,289,933	0.0418
19						
20	Water Heating Ctrlld (Off-Peak)					
21	14.01	1,950	145,364	500	3,900	0.0745
22				-500		
23	Controlled Service					
24	14.04,14.05,14.06,14.07	175,651	7,547,326	5,010	35,060	0.0430
25				-5,010		
26	Fixed Time of Delivery Service					
27	14.07	21,053	795,901	584	36,050	0.0378
28				-584		
29	Irrigation Service					
30	11.02	5,649	485,442	357	15,824	0.0859
31						
32						
33						
34						
35						
36	Column D Lines 21, 24 & 27					
37	Customers are also served					
38	under other commercial service.					
39						
40						
41	TOTAL Billed	4,723,152	372,732,561	134,877	35,018	0.0789
42	Total Unbilled Rev.(See Instr. 6)	27,270	2,211,258	0	0	0.0811
43	TOTAL	4,750,422	374,943,819	134,877	35,220	0.0789

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	Commercial and Industrial - cntd					
2	Commercial Time of Use					
3	10.03 & 10.04	550,130	42,300,462	606	907,805	0.0769
4						
5	Outdoor Lighting - Energy Only					
6	11.03	1,992	175,689	257	7,751	0.0882
7				-257		
8	Outdoor Lighting					
9	11.04	14,499	2,008,263	258	56,198	0.1385
10				-258		
11	Standby Service - Option A Firm					
12	11.01	165	19,176	5	33,000	0.1162
13						
14	Small Power Producer Rider					
15	12.01		931	27		
16				-27		
17						
18	Conservation Imp Prog Rev		-2,970,920			
19	Environmental Rider Rev		660,432			
20	Transmission Cost Recvy		-2,389,515			
21	Renewable Resource Rider		332,397			
22	Fuel Clause Adjustment Rec		2,290,872			
23	MN Rate Case Rev Reduction		-104,563			
24						
25	SUBTOTAL Billed	3,438,728	250,436,252	29,101	118,165	0.0728
26	Unbilled Rev (See Instr. 6)	26,667	1,937,794			0.0727
27	TOTAL - 442	3,465,395	252,374,046	29,101	119,082	0.0728
28						
29						
30						
31	Column D Lines 6,9 & 15					
32	customers are also served under					
33	other commerical service.					
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,723,152	372,732,561	134,877	35,018	0.0789
42	Total Unbilled Rev.(See Instr. 6)	27,270	2,211,258	0	0	0.0811
43	TOTAL	4,750,422	374,943,819	134,877	35,220	0.0789

SALES OF ELECTRICITY BY RATE SCHEDULES

- 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.
- 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.
- 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.
- 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).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- 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	Streetlighting - 444					
2	Outdoor Lighting-Energy Only					
3	11.03	6,696	556,196	280	23,914	0.0831
4				-280		
5	Outdoor lighting					
6	11.04	18,489	3,178,330	344	53,747	0.1719
7						
8	Conservation Imp Prog Rev		-15,260			
9	Environmental Rider Rev		10,143			
10	Transmission Cost Recvy		-18,725			
11	Renewable Resource Rider		3,133			
12	Fuel Clause Adjustment Rec		39,214			
13	MN Rate Case Rev Reduction		-745			
14						
15	Subtotal billed	25,185	3,752,286	344	73,212	0.1490
16	Unbilled Revenue	-97	-2,870			0.0296
17	TOTAL - 444	25,088	3,749,416	344	72,930	0.1495
18						
19	Other Public Authority-445					
20	Pumping and Sirens					
21	11.05,11.06	39,140	3,040,729	1,289	30,365	0.0777
22						
23	Conservation Imp Prog Rev		-28,190			
24	Environmental Rider Rev		7,849			
25	Transmission Cost Recvy		-28,183			
26	Renewable Resource Rider		4,388			
27	Fuel Clause Adjustment Rec		41,923			
28	MN Rate Case Rev Reduction		-1,257			
29						
30	Subtotal	39,140	3,037,259	1,289	30,365	0.0776
31	Unbilled Revenue	-147	723			-0.0049
32	TOTAL - 445	38,993	3,037,982	1,289	30,251	0.0779
33						
34	Revenue from Fuel Adjustment					
35	Clause is reported in footnote.					
36						
37	Column D, Line 3					
38	customers are also served under					
39	other commercial service.					
40						
41	TOTAL Billed	4,723,152	372,732,561	134,877	35,018	0.0789
42	Total Unbilled Rev.(See Instr. 6)	27,270	2,211,258	0	0	0.0811
43	TOTAL	4,750,422	374,943,819	134,877	35,220	0.0789

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2016	2016/Q4
FOOTNOTE DATA			

Schedule Page: 304.3 Line No.: 34 Column: a

The following revenue received through the fuel adjustment clause is included in the amounts reported on pages 304-304.3.

Residential - 440

9.01	Residential service	\$ (1,200,065)
9.02	Residential service (control demand)	(338,383)
14.01	Water heating - controlled (off-peak)	(15,698)
14.04,14.05,14.06,14.07	Controlled service	(338,480)
14.07	Fixed time of delivery service	(2,045)
11.03	Outdoor lighting- energy only	491
11.04	Outdoor lighting	(5,931)

Total residential		\$ (1,900,111)

Commercial and industrial - 442

10.01, 10.02	General service	\$ (1,332,691)
9.03	Farm service	(76,955)
10.03	Large general service	(3,747,282)
14.02	Real time pricing rider	-
10.05	Large general service (time of day)	(2,317,042)
14.03	Large general service rider	(97,841)
14.01	Water heating - controlled (off-peak)	3,385
14.04,14.05,14.06,14.07	Controlled service	(356,572)
14.07	Fixed time of delivery service	(18,242)
11.02	Irrigation service	(18,909)
10.04	Commercial time of use	3,697,654
11.03	Outdoor lighting - energy only	(2,010)
11.04	Outdoor lighting	(34,649)
11.01	Standby service-option A firm	(990)

Total commercial and industrial		\$ (4,302,144)

Streetlighting - 444

11.03	Outdoor lighting - energy only	\$ (12,527)
11.04	Outdoor lighting	(29,133)

Total streetlighting		\$ (41,660)

Other public authority - 445

11.05,11.06	Pumping and sirens	\$ (57,618)

Total		\$ (6,301,533)
		=====

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 not 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 long-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 Classification (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	RQ SALES					
2	Badger, SD	RQ	144	0.146	NA	NA
3	Newfolden, MN	RQ	174	0.477	NA	NA
4	Nielsville, MN	RQ	175	0.038	NA	NA
5	Shelly, MN	RQ	176	0.237	NA	NA
6						
7	NON-RQ SALES					
8	Midwest ISO Energy Market	OS	V9	NA	NA	NA
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, line 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
479	7,968	17,850	3,956	29,774	2
2,017	26,175	68,746	14,932	109,853	3
48	2,686	1,377	270	4,333	4
737	16,621	24,903	5,222	46,746	5
					6
					7
201,927		4,393,156		4,393,156	8
					9
					10
					11
					12
					13
					14
3,281	53,450	112,876	24,380	190,706	
201,927	0	4,393,156	0	4,393,156	
205,208	53,450	4,506,032	24,380	4,583,862	

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 310 Line No.: 2 Column: j

Fuel adjustment charges

Schedule Page: 310 Line No.: 3 Column: j

Fuel adjustment charges

Schedule Page: 310 Line No.: 4 Column: j

Fuel adjustment charges

Schedule Page: 310 Line No.: 5 Column: j

Fuel adjustment charges

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	1,722,605	1,692,309
5	(501) Fuel	53,727,773	42,347,510
6	(502) Steam Expenses	5,627,969	3,380,097
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,309,873	2,043,486
10	(506) Miscellaneous Steam Power Expenses	4,887,525	5,258,516
11	(507) Rents	4,971	3,169
12	(509) Allowances	28,032	108,771
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	68,308,748	54,833,858
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	861,972	811,657
16	(511) Maintenance of Structures	1,150,873	1,221,739
17	(512) Maintenance of Boiler Plant	7,510,932	6,587,242
18	(513) Maintenance of Electric Plant	1,239,787	3,051,732
19	(514) Maintenance of Miscellaneous Steam Plant	1,354,726	1,532,144
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	12,118,290	13,204,514
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	80,427,038	68,038,372
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	10,600	5,736
45	(536) Water for Power		
46	(537) Hydraulic Expenses	21,007	21,867
47	(538) Electric Expenses	34,694	49,063
48	(539) Miscellaneous Hydraulic Power Generation Expenses	17,444	12,569
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	83,745	89,235
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	12,385	430
54	(542) Maintenance of Structures	1,824	118
55	(543) Maintenance of Reservoirs, Dams, and Waterways	284,145	253,790
56	(544) Maintenance of Electric Plant	6,319	4,457
57	(545) Maintenance of Miscellaneous Hydraulic Plant		390
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	304,673	259,185
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	388,418	348,420

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	246,551	243,994
63	(547) Fuel	1,422,735	793,888
64	(548) Generation Expenses	2,210,732	2,141,702
65	(549) Miscellaneous Other Power Generation Expenses	701,799	667,764
66	(550) Rents	581,889	570,350
67	TOTAL Operation (Enter Total of lines 62 thru 66)	5,163,706	4,417,698
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	124,683	55,466
70	(552) Maintenance of Structures	34,077	62,819
71	(553) Maintenance of Generating and Electric Plant	518,892	681,184
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	143,507	85,607
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	821,159	885,076
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	5,984,865	5,302,774
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	63,225,919	78,149,806
77	(556) System Control and Load Dispatching	441,055	499,422
78	(557) Other Expenses	54,874	75,119
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	63,721,848	78,724,347
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	150,522,169	152,413,913
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	464,279	509,397
84			
85	(561.1) Load Dispatch-Reliability	71,442	71,570
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,471,306	2,550,472
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	1,069,288	902,670
89	(561.5) Reliability, Planning and Standards Development	763,506	713,221
90	(561.6) Transmission Service Studies	140	341
91	(561.7) Generation Interconnection Studies	625	
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	318,041	284,402
94	(563) Overhead Lines Expenses	599,907	406,001
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	22,085,013	16,995,586
97	(566) Miscellaneous Transmission Expenses	656,770	826,978
98	(567) Rents	49,879	37,889
99	TOTAL Operation (Enter Total of lines 83 thru 98)	28,550,196	23,298,527
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	204,233	217,105
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	50,158	14,396
104	(569.2) Maintenance of Computer Software	727,917	833,601
105	(569.3) Maintenance of Communication Equipment	91,267	62,694
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,175,177	1,109,533
108	(571) Maintenance of Overhead Lines	1,779,654	1,541,400
109	(572) Maintenance of Underground Lines	1,772	
110	(573) Maintenance of Miscellaneous Transmission Plant	1,195	2,975
111	TOTAL Maintenance (Total of lines 101 thru 110)	4,031,373	3,781,704
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	32,581,569	27,080,231

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	716,422	710,103
117	(575.3) Transmission Rights Market Facilitation	2,217	15,185
118	(575.4) Capacity Market Facilitation		1,455
119	(575.5) Ancillary Services Market Facilitation	28,980	23,330
120	(575.6) Market Monitoring and Compliance	66,617	9,134
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	814,236	759,207
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software	216,943	265,641
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)	216,943	265,641
131	TOTAL Regional Transmission and Market Op Exps (Total 123 and 130)	1,031,179	1,024,848
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	277,252	328,199
135	(581) Load Dispatching	224,423	240,934
136	(582) Station Expenses	310,375	258,974
137	(583) Overhead Line Expenses	273,050	319,375
138	(584) Underground Line Expenses	1,937,284	1,933,240
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	840,341	805,861
141	(587) Customer Installations Expenses	215,285	191,828
142	(588) Miscellaneous Expenses	3,677,204	3,311,530
143	(589) Rents	241,832	235,262
144	TOTAL Operation (Enter Total of lines 134 thru 143)	7,997,046	7,625,203
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	823,850	755,253
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	804,090	748,264
149	(593) Maintenance of Overhead Lines	4,188,930	3,330,118
150	(594) Maintenance of Underground Lines	1,029,141	1,005,602
151	(595) Maintenance of Line Transformers	74,444	87,213
152	(596) Maintenance of Street Lighting and Signal Systems	1,014,230	1,055,120
153	(597) Maintenance of Meters	736,064	823,318
154	(598) Maintenance of Miscellaneous Distribution Plant	123,052	84,207
155	TOTAL Maintenance (Total of lines 146 thru 154)	8,793,801	7,889,095
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	16,790,847	15,514,298
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	48,006	134,181
160	(902) Meter Reading Expenses	5,743,243	5,682,033
161	(903) Customer Records and Collection Expenses	5,229,744	5,825,857
162	(904) Uncollectible Accounts	930,000	780,001
163	(905) Miscellaneous Customer Accounts Expenses	525,093	369,270
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	12,476,086	12,791,342

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	595,471	619,603
168	(908) Customer Assistance Expenses	9,712,307	7,711,069
169	(909) Informational and Instructional Expenses	413,306	507,494
170	(910) Miscellaneous Customer Service and Informational Expenses	59,717	25,962
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	10,780,801	8,864,128
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	76,266	23,411
175	(912) Demonstrating and Selling Expenses	262,712	274,774
176	(913) Advertising Expenses		671
177	(916) Miscellaneous Sales Expenses	5,682	13,912
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	344,660	312,768
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	22,524,725	22,271,342
182	(921) Office Supplies and Expenses	6,914,141	6,877,617
183	(Less) (922) Administrative Expenses Transferred-Credit	2,472,648	2,210,241
184	(923) Outside Services Employed	1,353,266	1,777,537
185	(924) Property Insurance	3,168,173	2,059,414
186	(925) Injuries and Damages	2,248,103	2,128,998
187	(926) Employee Pensions and Benefits	3,113,201	3,083,224
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	4,390,992	2,193,553
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	490,312	320,655
192	(930.2) Miscellaneous General Expenses	1,539,761	1,345,237
193	(931) Rents	287,129	287,129
194	TOTAL Operation (Enter Total of lines 181 thru 193)	43,557,155	40,134,465
195	Maintenance		
196	(935) Maintenance of General Plant	1,137,692	1,890,817
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	44,694,847	42,025,282
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	269,222,158	260,026,810

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 320 Line No.: 86 Column: b

\$601,148 of the year-to-date expense recorded in Accounts 561 and 569 is designated as Account 561.BA expense.

Schedule Page: 320 Line No.: 86 Column: c

\$702,099 of the year-to-date expense recorded in Accounts 561 and 569 is designated as Account 561.BA expense.

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 Classification (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	Great River Energy	SF		100	NA	NA
2	Manitoba Hydro Electric Board	OS		NA	NA	NA
3	Minnesota Municipal Power Agency	SF		15	NA	NA
4	Missouri River Energy Services	SF		25	NA	NA
5	Nextera Energy Power Marketing Inc	SF		8	NA	NA
6	Northern States Power Company	OS		NA	NA	NA
7	Western Area Power Administration	OS		NA	NA	NA
8	Western Area Power Administration WEC	OS		NA	NA	NA
9	Beltrami Electric Cooperative	RQ		NA	NA	NA
10	Nodak Rural Electric Cooperative	RQ		NA	NA	NA
11	P K M Electric Cooperative	RQ		NA	NA	NA
12	Red Lake Rural Electric Cooperative	RQ		NA	NA	NA
13	Cass County Electric Cooperative	RQ		NA	NA	NA
14	Sioux Valley Electric Cooperative	RQ		NA	NA	NA
	Total					

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 Classification (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	Whetstone Valley Electric Cooperative	RQ		NA	NA	NA
2	Prairie Lakes Muni Waste	RQ		NA	NA	NA
3	Dakota Magic Casino	RQ		NA	NA	NA
4	Kindred School	RQ		NA	NA	NA
5	Stevens Community Medical	OS		NA	NA	NA
6	City of Detroit Lakes	OS		NA	NA	NA
7	American Crystal Sugar	OS		NA	NA	NA
8	Dakota Wind Exchange	OS		NA	NA	NA
9	Hendricks Wind I	OS		NA	NA	NA
10	Borderline Wind	OS		NA	NA	NA
11	Univ. of MN - Morris	OS		NA	NA	NA
12	FPL Energy ND II, LLC	OS		NA	NA	NA
13	Langdon Wind, LLC	OS		NA	NA	NA
14	Turtle Mountain Community College	OS		NA	NA	NA
	Total					

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 Classification (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	LacQui Parle School	OS		NA	NA	NA
2	Pembina Border Station	OS		NA	NA	NA
3	Lake Region State College	OS		NA	NA	NA
4	Ashtabula Wind III LLC	OS		NA	NA	NA
5	Ashtabula Wind III LLC - Curtailment	OS		NA	NA	NA
6	MN Co Generation	OS		NA	NA	NA
7	ND Co Generation	OS		NA	NA	NA
8	SD Co Generation	OS		NA	NA	NA
9						
10	Midwest ISO Energy Market	OS		NA	NA	NA
11	Southwest Power Pool ISO Energy Market	OS		NA	NA	NA
12	Miscellaneous Energy Market Changes					
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 monthly (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)	
			2,025,000			2,025,000	1
54,000				92,070		92,070	2
			-139,500			-139,500	3
			-61,875			-61,875	4
			-22,000			-22,000	5
204,000				3,696,691		3,696,691	6
-2,827				-56,682		-56,682	7
30,621				1,018,141		1,018,141	8
107,726			855,766	5,722,812	70,426	6,649,004	9
9,566			106,704	530,907		637,611	10
10,290			105,809	574,335		680,144	11
9,343			98,102	495,954		594,056	12
			6,162			6,162	13
23			75	1,140		1,215	14
2,472,777			3,064,674	60,090,819	70,426	63,225,919	

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 monthly (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)	
			688			688	1
			11,660			11,660	2
			30,960			30,960	3
			22,200			22,200	4
			23,760			23,760	5
935			1,163	1,403		2,566	6
87				873		873	7
1				362		362	8
2,374				106,850		106,850	9
1,668				50,036		50,036	10
5,052				277,835		277,835	11
54,136				1,618,669		1,618,669	12
71,084				2,787,934		2,787,934	13
289				10,959		10,959	14
2,472,777			3,064,674	60,090,819	70,426	63,225,919	

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 monthly (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)	
36				1,327		1,327	1
1,067				38,872		38,872	2
4,501				141,093		141,093	3
223,739				6,209,204		6,209,204	4
6,854				189,568		189,568	5
209				20,047		20,047	6
46				232		232	7
36				1,320		1,320	8
							9
1,649,434				36,012,391		36,012,391	10
28,487				547,110		547,110	11
				-634		-634	12
							13
							14
2,472,777			3,064,674	60,090,819	70,426	63,225,919	

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 326 Line No.: 1 Column: a

January through December 2016

Schedule Page: 326 Line No.: 3 Column: a

January through December 2016

Schedule Page: 326 Line No.: 4 Column: a

January through May 2016

Schedule Page: 326 Line No.: 5 Column: a

January through May 2016

Schedule Page: 326 Line No.: 9 Column: l

Nomination charge

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	Badger, SD	Western Area Power Administration	Badger, SD	LFP
2	Newfolden, MN	Western Area Power Administration	Newfolden, MN	LFP
3	Nielsville, MN	Western Area Power Administration	Nielsville, MN	LFP
4	Shelly, MN	Western Area Power Administration	Shelly, MN	LFP
5	Fort Totten Indian Agency	Western Area Power Administration	Fort Totten, ND	LFP
6	State Development Center	Western Area Power Administration	Grafton, ND	LFP
7	North Dakota School for Deaf	Western Area Power Administration	Devils Lake, ND	LFP
8	North Dakota School of Forestry	Western Area Power Administration	Bottineau, ND	LFP
9	North Dakota College of Science	Western Area Power Administration	Wahpeton, ND	LFP
10	Turtle Mountain Indian Agency	Western Area Power Administration	Belcourt, ND	LFP
11	Oakes O&M Headquarters	Western Area Power Administration	Oakes, ND	LFP
12	Minnkota Power Cooperative, Inc.	Minnkota Power Cooperative, Inc.	Various Interconnects	OS
13		U.S. Bureau of Reclamation	Otter Tail Power Company	OS
14		Various Companies	Otter Tail Power Company	OS
15		Various Companies	Otter Tail Power Company	OS
16	Midwest Independent System Operator	Various Companies	Various Companies	OS
17	See Footnote			
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred 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 (Substation 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)	
4	(1)	Badger, SD		1,366	1,307	1
4	(1)	Newfolden, MN		2,981	2,786	2
4	(1)	Nielsville, MN		647	605	3
4	(1)	Shelly, MN		1,652	1,544	4
4	(1)	Fort Totten, ND		357	337	5
4	(1)	Grafton, ND		4,764	4,494	6
4	(1)	Devils Lake, ND		469	438	7
4	(1)	Bottineau, ND		1,196	1,118	8
4	(1)	Wahpeton, ND		8,764	8,229	9
4	(1)	Belcourt, ND		2,041	1,925	10
4	(1)	Oakes, ND		55	53	11
See Footnote	(1)	Various Interconnect		234,333	219,003	12
		(1)		2,508		13
		(1)		-288,598		14
		(1)		-2,508		15
OATT	System	System				16
	See Footnote					17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	-29,973	241,839	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred 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.
9,802			9,802	1
25,532			25,532	2
7,012			7,012	3
16,848			16,848	4
1,526			1,526	5
22,815			22,815	6
5,993			5,993	7
10,377			10,377	8
92,617			92,617	9
32,852			32,852	10
2,063			2,063	11
	216,203		216,203	12
				13
				14
				15
		36,073,730	36,073,730	16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
227,437	216,203	36,073,730	36,517,370	

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

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

Original Service Agreement No. 30 under Otter Tail Power Company FERC Electric Tariff, Original Volume No. 1

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

Various companies

Miscellaneous losses - mwh received

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

Midwest Independent System Operator Transmission

Schedule 1 Network = 359,327

Schedule 1 Firm = 46,554

Schedule 1 Non-firm = 8,687

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

Lines 1-10 Otter Tail Power Company wheels WAPA's portion of customers' load.

Line 11 Otter Tail Power Company wheels WAPA's total load to customer.

Line 12 Otter Tail Power Company wheels MPC's total load to various interconnects.

Lines 13-15 contain losses and regulation that result from interconnects with various companies in the integrated system.

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

(1) Various points of interconnect in the integrated system.

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 Tariff (d)	Total Revenue (e)
1	Not applicable.				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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19					
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23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

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			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Otter Tail Power Co.	FNS					5,278,155	5,278,155
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						5,278,155	5,278,155

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 332 Line No.: 1 Column: g

The expenses incurred are for transmission of electricity and supporting services provided by the Midcontinent Independent System Operator and the Southwest Power Pool.

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	247,235
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	125,132
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	215,103
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	30,763
6	Directors Fees and Expenses	675,878
7	Miscellaneous Labor Not Provided for Elsewhere	234,318
8	News Release Distribution - Sundog Interactive, Inc.	6,332
9	Energy Innovation Celebration-Great Plains Institute	5,000
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
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21		
22		
23		
24		
25		
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38		
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41		
42		
43		
44		
45		
46	TOTAL	1,539,761

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of acquisition 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			1,830,060		1,830,060
2	Steam Production Plant	16,821,716	124,965			16,946,681
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	515,931				515,931
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	12,171,123	-3,618			12,167,505
7	Transmission Plant	6,854,504				6,854,504
8	Distribution Plant	11,027,172				11,027,172
9	Regional Transmission and Market Operation					
10	General Plant	2,709,952				2,709,952
11	Common Plant-Electric					
12	TOTAL	50,100,398	121,347	1,830,060		52,051,805

B. Basis for Amortization Charges

The \$1,830,060 is amortization of:

Franchises and Consents (302):
 \$ 41,847 for hydro plant license with a remaining life of 5.92 years at a 3.21% rate.

Miscellaneous Intangible Plant (303):
 \$ 1,788,213 for computer software with a 5-year service life at a 20% rate.

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	STEAM PRODUCTION						
13	Big Stone Plant						
14	311	66,364	60.88	-11.80	2.99	SQ	30.15
15	312	160,368	48.46	-11.80	3.27	SQ	30.19
16	314	12,497	44.26	-11.80	1.77	SQ	30.21
17	315	15,448	53.30	-11.80	2.72	SQ	30.17
18	316	1,599	47.27	-11.40	2.09	SQ	30.19
19							
20	Hoot Lake Plant						
21	311 - Units 2, 3	131	36.74	-12.70	2.30	SQ	6.44
22	312 - Units 2, 3	16,589	14.70	-12.70	7.67	SQ	6.45
23	314 - Units 2, 3	1,323	23.59	-12.70	3.75	SQ	6.44
24	315 - Units 2, 3	232	26.40	-12.70	3.27	SQ	6.44
25	316 - Units 2, 3	325	16.36	-12.60	6.31	SQ	6.45
26							
27	Coyote Plant						
28	311	9,617	52.50	-8.60	1.47	SQ	25.55
29	312	31,117	48.94	-8.60	1.66	SQ	25.56
30	314	11,226	39.24	-8.60	2.17	SQ	25.59
31	315	3,992	47.93	-8.60	1.66	SQ	25.56
32	316	1,028	39.13	-8.30	2.34	SQ	25.58
33							
34	STEAM PROD	331,856					
35							
36	HYDRO PRODUCTION						
37	Hoot Lake Hydro						
38	331	1	61.02		0.24	SQ	6.44
39	332	40	29.85		2.11	SQ	6.44
40	333	10	36.00		1.43	SQ	6.44
41	334	4	30.62		1.97	SQ	6.44
42	335	35	8.91		11.17	SQ	6.45
43							
44	Wright Hydro						
45	331	4	30.62		2.97	SQ	6.44
46	332	579	9.58		10.06	SQ	6.45
47	333	131	9.28		3.72	SQ	6.45
48	334	66	17.75		5.11	SQ	6.45
49	335	60	12.19		8.08	SQ	6.45
50							

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	Pisgah Hydro						
13	331	2	38.62		2.37	SQ	6.44
14	332	186	12.95		7.68	SQ	6.45
15	333	68	15.85		6.60	SQ	6.45
16	334	36	17.81		5.66	SQ	6.45
17	335	47	8.91		11.73	SQ	6.45
18							
19	Dayton Hollow Hydro						
20	331	11	9.92		10.38	SQ	6.45
21	332	845	10.67		10.14	SQ	6.45
22	333	95	14.14		6.50	SQ	6.45
23	334	57	21.28		4.53	SQ	6.45
24	335	78	8.93		10.81	SQ	6.45
25							
26	Taplin Gorge Hydro						
27	331	2	74.10		0.90	SQ	6.44
28	332	239	16.27		6.16	SQ	6.45
29	333	1	81.70		0.78	SQ	6.44
30	334	15	22.12		3.96	SQ	6.45
31	335	57	11.72		8.56	SQ	6.45
32							
33	Bemidji Hydro						
34	331	100	13.16		7.76	SQ	6.45
35	332	435	13.09		8.27	SQ	6.45
36	333	120	19.59		5.75	SQ	6.45
37	334	2	72.95		5.74	SQ	6.44
38	335	1	11.86		9.60	SQ	6.45
39							
40	HYDRO PROD	3,327					
41							
42	OTHER PRODUCTION						
43	Jamestown Peaking #1						
44	341	75	24.44	-1.40	3.34	SQ	8.41
45	342	184	16.47	-1.40	5.95	SQ	8.41
46	343	509	32.73	-1.40	2.28	SQ	8.40
47	345	40	46.84	-1.40	3.21	SQ	8.40
48	346	52	17.28	-1.40	7.38	SQ	8.41
49							
50							

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	Lake Preston Peaking						
13	341	47	29.12	-2.40	2.70	SQ	8.40
14	342	78	28.17	-2.40	3.12	SQ	8.40
15	343	369	39.12	-2.40	1.67	SQ	8.40
16	345	36	41.94	-2.40	1.45	SQ	8.40
17	346	2	38.99	-2.40	1.46	SQ	8.40
18							
19	Jamestown Peaking #2						
20	341	12	17.00	-1.40	6.03	SQ	8.41
21	342	7	26.95	-1.40	2.32	SQ	8.40
22	343	498	37.88	-1.40	1.73	SQ	8.40
23	345	52	15.33	-1.40	8.70	SQ	8.41
24	346		37.52	-1.40	-0.66	SQ	8.40
25							
26	Fergus Falls Ctrl Ctr						
27	343	256	33.94		2.86	SQ	15.18
28							
29	Solway Combust Turbine						
30	341	2,852	32.95	-0.40	2.85	SQ	22.79
31	342	639	33.45	-0.40	2.81	SQ	22.79
32	343	14,094	33.22	-0.40	2.90	SQ	22.79
33	345	890	33.22	-0.40	3.01	SQ	22.79
34	346	217	32.09	-0.40	2.94	SQ	22.79
35							
36	Langdon Wind Energy						
37	341	1,696	24.29	-1.50	4.08	SQ	17.11
38	344	48,108	24.15	-1.50	4.15	SQ	17.11
39	345	5,156	23.80	-1.50	4.16	SQ	17.11
40	346	56	19.38	-1.50	5.06	SQ	17.12
41							
42	Ashtabula Wind Energy						
43	341	2,338	24.27	-1.20	4.05	SQ	18.07
44	344	78,371	24.17	-1.20	4.13	SQ	18.07
45	345	4,611	24.16	-1.20	4.07	SQ	18.07
46	346	25	20.46	-1.20	4.85	SQ	18.07
47							
48							
49							
50							

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	Luverne Wind Energy						
13	341	1,703	24.26	-2.00	4.05	SQ	19.02
14	344	49,924	24.18	-2.00	4.11	SQ	19.02
15	345	3,656	24.25	-2.00	4.06	SQ	19.02
16	346	66	20.58	-2.00	4.80	SQ	19.02
17							
18	OTHER PROD	216,619					
19							
20	TRANSMISSION PLANT						
21	350.1	10,372			1.43		70.00
22	353	66,397	65.15	-5.00	1.57	R1	52.75
23	354	81,240	70.00	-10.00	1.60	R5	65.48
24	355	60,552	70.36	-50.00	1.98	R2	53.90
25	356	64,736	70.24	-30.00	1.72	R2	54.34
26	358	6	41.72	-5.00	1.30	S4	9.83
27	SUBTOTAL	283,303					
28							
29	DISTRIBUTION PLANT						
30	362	55,180	40.64	5.00	2.12	SC	32.19
31	364	30,229	68.08	-75.00	2.47	R3	47.99
32	365	10,683	65.20	-100.00	2.78	R2.5	43.86
33	367	37,618	39.93	-5.00	2.34	R4	24.61
34	368	76,466	40.13	50.00	1.24	R2.5	28.29
35	369	-1,794	55.21	-150.00	4.16	S5	32.68
36	369.1	23,076	45.14	-20.00	2.59	R4	30.25
37	370	16,048	29.78		3.20	L0.5	20.68
38	370.1	2,153	12.12		8.89	R5	2.79
39	370.2	5	5.00		20.00	SQ - Amortized	1.00
40	371.2	3,391	23.19	10.00	3.89	L0	16.90
41	373	2,381	22.52	-5.00	3.39	L0.5	15.11
42	SUBTOTAL	255,436					
43							
44	GENERAL PLANT						
45	390	14,342	47.50	10.00	2.01	R1.5	31.17
46	390.1	3,267	33.05	49.70	0.49	SQ	15.18
47	390.2	444	27.87	33.80	1.31	SQ	10.36
48	390.3	2,134	49.73	92.70	-1.99	SQ	19.93
49	391	492	15.00		6.67	SQ - Amortized	5.53
50	391.1	294	10.00		10.00	SQ - Amortized	4.34

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	General Plant (cont'd)						
13	391.2	145	10.00		10.00	SQ - Amortized	3.53
14	391.5	1,723	5.00		20.00	SQ - Amortized	1.72
15	391.6	737	5.00		20.00	SQ - Amortized	1.81
16	392	16,080					
17	Aircraft	1,010	7.00	39.00			
18	Autos		5.00	15.00			
19	Light Trucks		10.00	10.00			
20	Heavy Trucks & Semi		10.00	15.00			
21	Tractors (includes		10.00	15.00			
22	Cranes)						
23	Trailers		15.00	10.00			
24	Portable Oil Purifier		10.00	20.00			
25	Trenchers		10.00	10.00			
26	Misc. Light Equipment		10.00	10.00			
27	Misc. Heavy Equipment		15.00	15.00			
28	394	2,336	15.00		6.67	SQ - Amortized	8.87
29	394.2	278	15.00		6.67	SQ - Amortized	7.66
30	395		15.00		6.67	SQ - Amortized	
31	396	389	26.04	20.00	2.56	L0	17.28
32	397	509	15.00		6.67	SQ - Amortized	9.26
33	397.1	611	10.00		10.00	SQ - Amortized	5.83
34	397.2	2,444	15.00		6.67	SQ - Amortized	8.08
35	397.3	187	10.00		10.00	SQ - Amortized	6.40
36	397.4	1,034	40.29	5.00	2.00	R3	24.87
37	SUBTOTAL	48,456					
38							
39	TOTAL	1,138,997					
40							
41	SUBACCOUNTS USED						
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 12/31/2016	2016/Q4
FOOTNOTE DATA			

Schedule Page: 336.4 Line No.: 41 Column: a

SUBACCOUNTS USED

- 369.1 Underground Services
- 370.1 Load Management Switches
- 370.2 Interruption Monitors
- 371.2 All Other Private Lighting
- 390.1 General Office Building
- 390.2 Fleet Service Center Building
- 390.3 Central Stores Building
- 391.1 Office Equipment
- 391.2 Duplicating Equipment
- 391.5 Computer Systems
- 391.6 Computer Related Equipment
- 394.2 AMR Equipment
- 397.1 Radio Telecommunication Equipment
- 397.2 Microwave Equipment
- 397.3 Radio Load Control Equipment
- 397.4 Communication Towers

Column (b) is the balance of plant in service (except land) at the beginning of the year, less the associated reserve for accumulated depreciation, and includes amounts tentatively classified in Account 106, Completed Construction Not Classified.

Column (e) rates are applied to the original cost per books (Accounts 101 and 106) at the close of the prior month except when major additions and retirements occur which significantly affect depreciation expense.

Column (d) factors are a composite of rates allowed in the jurisdictions served.

Name of Respondent
Otter Tail Power Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2016

Year/Period of Report
End of 2016/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	Regulatory Agency Assessments:				
2	MN Dept. of Commerce/Public Util. Commission	477,255		477,255	
3					
4	SD Public Utilities Commission	51,670		51,670	
5					
6	ND Public Service Commission	12,704		12,704	
7					
8	Federal Energy Regulatory Commission	546,925		546,925	
9					
10	Other Expenses:				
11	MN Public Utilities Commission:				
12	E017/GR-15-1033 (MN Rate Case)		2,333,460	2,333,460	
13	Miscellaneous		69,064	69,064	
14					
15	ND Public Service Commission:				
16	Miscellaneous		20,185	20,185	
17					
18	SD Public Utilities Commission:				
19	Miscellaneous		6,405	6,405	
20					
21	FERC				
22	ER14-2850/ER14-2851 (Integr IS Parties/SPP)		696,471	696,471	
23	Miscellaneous		176,853	176,853	
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	1,088,554	3,302,438	4,390,992	

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 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
Electric	928	397,200					2
							3
Electric	928	51,670					4
							5
Electric	928	12,704					6
							7
Electric	928	546,925					8
							9
							10
							11
Electric	928	2,333,460	1,730,054		648,465	1,081,589	12
Electric	928	149,119					13
							14
							15
Electric	928	20,185					16
							17
							18
Electric	928	6,405					19
							20
							21
Electric	928	573,471					22
Electric	928	299,853					23
							24
							25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		4,390,992	1,730,054		648,465	1,081,589	46

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: | a. Overhead |
| (1) Generation | b. Underground |
| a. hydroelectric | (3) Distribution |
| i. Recreation fish and wildlife | (4) Regional Transmission and Market Operation |
| ii Other hydroelectric | (5) Environment (other than equipment) |
| b. Fossil-fuel steam | (6) Other (Classify and include items in excess of \$50,000.) |
| c. Internal combustion or gas turbine | (7) Total Cost Incurred |
| d. Nuclear | B. Electric, R, D & D Performed Externally: |
| e. Unconventional generation | (1) Research Support to the electrical Research Council or the Electric Power Research Institute |
| f. Siting and heat rejection | |
| (2) Transmission | |

Line No.	Classification (a)	Description (b)
1	Electric Utility R&D	
2		
3	PERFORMED INTERNALLY:	
4	Other	Miscellaneous
5	Other	Miscellaneous
6		
7	Sub-Total Performed Internally	
8		
9	PERFORMED EXTERNALLY:	
10		Microbeam Technologies
11		Chartwell Inc
12		E Source Companies LLC
13		
14		
15	Sub-Total Performed Externally	
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32	SUM OF ABOVE	
33		
34		
35		
36		
37		
38		

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
16,555		920	16,555		4
690		930.2	690		5
					6
17,245			17,245		7
					8
					9
	10,500	506	10,500		10
	10,196	930.2	10,196		11
	15,690	930.2	15,690		12
					13
					14
	36,386		36,386		15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
17,245	36,386		53,631		32
					33
					34
					35
					36
					37
					38

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 Terminating 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)	70,350,399		70,350,399
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	16,654,000		16,654,000
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	16,654,000		16,654,000
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,236,593		1,236,593
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,236,593		1,236,593
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock (151)	53,087		53,087
79	Miscellaneous Deferred Debits (186)	1,314,248		1,314,248
80	Other Electric Revenue (456)	328,253		328,253
81	Expenses of Nonutility Operations (417.1)	130,512		130,512
82	Expenses for Certain Civic, Political & Related Acty (426.4)	99,531		99,531
83	Other Deductions (426.5)	133,953		133,953
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	2,059,584		2,059,584
96	TOTAL SALARIES AND WAGES	90,300,576		90,300,576

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 354 Line No.: 77 Column: a

Salaries and wages are included in the specified accounts because they are either not provided for elsewhere, are nonutility in nature, or are nonoperating.

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of <u>2016/Q4</u>
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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
Otter Tail Power Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2016

Year/Period of Report
End of 2016/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)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8	Not available.				
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					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent
Otter Tail Power Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2016

Year/Period of Report
End of 2016/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:

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	876	12	8	875	1				
2	February	808	12	9	807	1				
3	March	765	1	9	764	1				
4	Total for Quarter 1				2,446	3				
5	April	693	11	9	692	1				
6	May	614	24	16	613	1				
7	June	669	10	17	668	1				
8	Total for Quarter 2				1,973	3				
9	July	730	22	14	729	1				
10	August	713	3	17	712	1				
11	September	631	1	15	630	1				
12	Total for Quarter 3				2,071	3				
13	October	692	24	9	691	1				
14	November	712	1	9	711	1				
15	December	903	15	9	902	1				
16	Total for Quarter 4				2,304	3				
17	Total Year to Date/Year				8,794	12				

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 400 Line No.: 9 Column: b

Due to meter data corrections, the monthly peak MW for July through September have changed. In some cases the monthly peak day, peak hour, firm network service for self, and firm network service for others may have changed.

Schedule Page: 400 Line No.: 13 Column: b

The peak numbers for October through December are estimated and are from MISO's S-55 settlement data.

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	Monthly Peak MW - Total	Day of Monthly Peak	Hour of Monthly Peak	Imports into ISO/RTO	Exports from ISO/RTO	Through and Out Service	Network Service Usage	Point-to-Point Service Usage	Total Usage
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(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

Otter Tail Power Company

This Report Is:

(1) An Original(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2016

Year/Period of Report

End of 2016/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)	4,750,422
3	Steam	2,264,126	23	Requirements Sales for Resale (See instruction 4, page 311.)	3,281
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	201,927
5	Hydro-Conventional	25,587	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	11,277
7	Other	532,066	27	Total Energy Losses	55,837
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	5,022,744
9	Net Generation (Enter Total of lines 3 through 8)	2,821,779			
10	Purchases	2,472,777			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	-29,973			
17	Delivered	241,839			
18	Net Transmission for Other (Line 16 minus line 17)	-271,812			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	5,022,744			

Name of Respondent Otter Tail Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report End of <u>2016/Q4</u>
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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:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	477,445	11,921	876	12	800
30	February	431,469	17,067	808	12	900
31	March	455,871	14,150	765	1	900
32	April	372,557	11,296	693	11	900
33	May	323,736	7,141	614	24	1600
34	June	424,575	19,450	669	10	1700
35	July	347,002	22,423	730	22	1400
36	August	364,155	15,143	713	3	1700
37	September	352,136	30,501	631	1	1500
38	October	489,995	13,849	692	24	900
39	November	439,647	18,977	712	1	900
40	December	544,156	20,009	903	15	900
41	TOTAL	5,022,744	201,927			

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 401 Line No.: 16 Column: b

Includes interchange transactions and losses thereon.

Schedule Page: 401 Line No.: 17 Column: b

Includes interchange transactions and losses thereon.

Schedule Page: 401 Line No.: 27 Column: b

Includes all retail, wholesale, and transmission wheeling service system losses, losses on other systems due to sales for resale, and inadvertent energy imbalances.

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: Coyote (b)			Plant Name: Big Stone (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1981			1975		
4	Year Last Unit was Installed	1981			1975		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	144.90			223.15		
6	Net Peak Demand on Plant - MW (60 minutes)	149			258		
7	Plant Hours Connected to Load	6689			7822		
8	Net Continuous Plant Capability (Megawatts)	150			256		
9	When Not Limited by Condenser Water	150			256		
10	When Limited by Condenser Water	150			256		
11	Average Number of Employees	80			85		
12	Net Generation, Exclusive of Plant Use - KWh	844224830			1203965886		
13	Cost of Plant: Land and Land Rights	713587			374603		
14	Structures and Improvements	34255835			85108485		
15	Equipment Costs	139968823			240840837		
16	Asset Retirement Costs	1377063			896678		
17	Total Cost	176315308			327220603		
18	Cost per KW of Installed Capacity (line 17/5) Including	1216.8068			1466.3706		
19	Production Expenses: Oper, Supv, & Engr	687662			649528		
20	Fuel	17335855			27395323		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	2024793			2217467		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	561010			893967		
26	Misc Steam (or Nuclear) Power Expenses	661116			2304075		
27	Rents	4521			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	333489			358800		
30	Maintenance of Structures	243575			588387		
31	Maintenance of Boiler (or reactor) Plant	3583437			2729805		
32	Maintenance of Electric Plant	766695			550453		
33	Maintenance of Misc Steam (or Nuclear) Plant	595604			356955		
34	Total Production Expenses	26797757			38044760		
35	Expenses per Net KWh	0.0317			0.0316		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	695521	6739	0	770468	1635	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	6910	140000	0	8278	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	23.881	52.290	0.000	37.321	51.280	0.000
41	Average Cost of Fuel per Unit Burned	23.752	54.558	0.000	37.263	67.450	0.000
42	Average Cost of Fuel Burned per Million BTU	1.719	9.279	0.000	2.251	11.471	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.021	0.000	0.000	0.023	0.000	0.000
44	Average BTU per KWh Net Generation	11439.000	0.000	0.000	10881.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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: <i>Solway</i> (b)	Plant Name: (c)				
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas Turbine					
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional					
3	Year Originally Constructed	2003					
4	Year Last Unit was Installed	2003					
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	44.50			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	49			0		
7	Plant Hours Connected to Load	1088			0		
8	Net Continuous Plant Capability (Megawatts)	43			0		
9	When Not Limited by Condenser Water	43			0		
10	When Limited by Condenser Water	43			0		
11	Average Number of Employees	2			0		
12	Net Generation, Exclusive of Plant Use - KWh	39508537			0		
13	Cost of Plant: Land and Land Rights	89809			0		
14	Structures and Improvements	4411779			0		
15	Equipment Costs	24158852			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	28660440			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	644.0548			0		
19	Production Expenses: Oper, Supv, & Engr	96			0		
20	Fuel	1024456			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	311358			0		
26	Misc Steam (or Nuclear) Power Expenses	142384			0		
27	Rents	-167			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	10547			0		
30	Maintenance of Structures	16156			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	292799			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	4338			0		
34	Total Production Expenses	1801967			0		
35	Expenses per Net KWh	0.0456			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Natural Gas	Oil				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MMBTU	Barrels				
38	Quantity (Units) of Fuel Burned	405084	5	0	0	0	
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	406400	140000	0	0	0	
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	2.545	0.000	0.000	0.000	0.000	
41	Average Cost of Fuel per Unit Burned	2.529	94.500	0.000	0.000	0.000	
42	Average Cost of Fuel Burned per Million BTU	2.529	16.071	0.000	0.000	0.000	
43	Average Cost of Fuel Burned per KWh Net Gen	0.026	0.000	0.000	0.000	0.000	
44	Average BTU per KWh Net Generation	10254.000	0.000	0.000	0.000	0.000	

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000

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: <i>Hoot Lake</i> (d)	Plant Name: <i>Jamestown</i> (e)	Plant Name: <i>Lake Preston</i> (f)	Line No.						
Steam	Gas Turbine	Gas Turbine	1						
Conventional	Conventional	Conventional	2						
1959	1976	1978	3						
1964	1978	1978	4						
128.50	48.11	24.10	5						
144	48	21	6						
5462	49	49	7						
140	42	20	8						
140	42	20	9						
140	42	20	10						
37	1	0	11						
215935023	317454	409894	12						
565967	24614	12339	13						
6084167	305657	229834	14						
53583218	7684747	4033048	15						
484409	0	0	16						
60717761	8015018	4275221	17						
472.5118	166.5978	177.3951	18						
299796	851	1040	19						
7590716	202438	195841	20						
0	0	0	21						
1312850	0	0	22						
0	0	0	23						
0	0	0	24						
857641	57680	24415	25						
980155	1144	502	26						
450	0	300	27						
28032	0	0	28						
185223	76854	31293	29						
322355	16451	1472	30						
1227494	0	0	31						
-72321	135797	39415	32						
369618	7857	0	33						
13102009	499072	294278	34						
0.0607	1.5721	0.7179	35						
Coal	Oil	Oil	Oil	Oil	Oil	Oil	Oil	Oil	36
Tons	Barrels	Barrels	Barrels	Barrels	Barrels	Barrels	Barrels	Barrels	37
134493	2490	0	1557	0	0	1841	0	0	38
9224	140000	0	140000	0	0	140000	0	0	39
52.445	69.340	0.000	0.000	0.000	0.000	53.676	0.000	0.000	40
54.000	65.520	0.000	130.032	0.000	0.000	106.390	0.000	0.000	41
2.927	11.143	0.000	22.114	0.000	0.000	18.094	0.000	0.000	42
0.035	0.000	0.000	0.638	0.000	0.000	0.478	0.000	0.000	43
11578.000	0.000	0.000	28835.000	0.000	0.000	26409.000	0.000	0.000	44

Name of Respondent
Otter Tail Power Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2016

Year/Period of Report
End of 2016/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	38
0	0	0	39
0.000	0.000	0.000	40
0.000	0.000	0.000	41
0.000	0.000	0.000	42
0.000	0.000	0.000	43
0.000	0.000	0.000	44

Name of Respondent
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(Mo, Da, Yr)
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Year/Period of Report
End of 2016/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	38
0	0	0	39
0.000	0.000	0.000	40
0.000	0.000	0.000	41
0.000	0.000	0.000	42
0.000	0.000	0.000	43
0.000	0.000	0.000	44

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 402 Line No.: -1 Column: b
Coyote - Joint facility operated by Otter Tail Power Company

Schedule Page: 402 Line No.: -1 Column: c
Big Stone - Joint facility operated by Otter Tail Power Company

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: Not applicable (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

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Otter Tail Power Company

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(Mo, Da, Yr)
12/31/2016

Year/Period of Report
End of 2016/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

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)	0	FERC Licensed Project No. Plant Name: (d)	0	FERC Licensed Project No. Plant Name: (e)	0	Line No.
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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	Hydro:					
2	Hoot Lake	1914	1.00	0.8	5,815	661,464
3	Wright	1922	0.40	0.5	2,766	1,776,422
4	Pisgah	1917	0.52	0.7	4,978	712,212
5	Dayton Hollow	1909	0.97	1.1	7,753	1,864,753
6	Taplin Gorge	1925	0.56	0.5	4,275	966,267
7	Bemidji	1941	0.74			1,356,162
8						
9	Internal Combustion:					
10	Fergus Falls Control Center	1995	1.83	2.1	22	591,638
11	Diesel Generators		2.26	1.8		
12						
13	Wind Turbine Plants					
14	Langdon	2007	40.50	40.4	149,689	79,314,730
15	Ashtabula	2008	48.00	48.2	159,793	116,330,502
16	Luverne	2009	49.50	49.9	182,327	72,965,876
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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
846,945	10,927		24,261	-		2
3,755,650	5,991		53,809	-		3
976,971	6,149		43,690	-		4
1,767,539	6,253		94,766	-		5
1,887,239	6,434		55,350	-		6
	23,302		32,797	-		7
						8
						9
281,732	1,623		12,025	Oil		10
				Oil		11
						12
						13
1,962,653	858,174		59,935			14
2,413,746	988,765		45,503			15
1,462,242	967,072		45,551			16
						17
						18
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						46

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 410 Line No.: 11 Column: b
 Various.

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 (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Alexandria	MN Border	345.00	345.00	Steel Tower	101.00		1
2	Brookings	MN Border	345.00	345.00	Steel Tower	10.00		1
3	Cedar Mountain	Helena	345.00	345.00	Steel Tower	73.00		2
4	Cedar Mountain	Lyon County	345.00	345.00	Steel Tower	49.00		2
5	Center	Maple River	345.00	345.00	Alum Tower	48.00		1
6	Chub Lake	Hampton	345.00	345.00	Steel Tower	18.00		1
7	Helena	Chub Lake	345.00	345.00	Steel Tower	21.00		1
8	Lyon County	Hazel Creek	345.00	345.00	Steel Tower	25.00		1
9	Lyon County	MN Border	345.00	345.00	Steel Tower	49.00		1
10	MN Border	Bison	345.00	345.00	Steel Tower	35.00		1
11	Monticello	Quarry Sub	345.00	345.00	Steel Tower	29.00		1
12	St Cloud	Alexandria	345.00	345.00	Steel Tower	77.00		1
13								
14	Fergus Falls	Inman	230.00	230.00	Wood H	19.00		1
15	Fergus Falls	Wahpeton	230.00	230.00	Wood H	29.00		1
16	Wahpeton	Hankinson	230.00	230.00	Wood H	26.00		1
17	Hankinson	Forman	230.00	230.00	Wood H	36.00		1
18	Forman	Ellendale	230.00	230.00	Wood H	47.00		1
19	Audubon (W 1/10)	Badoura	230.00	230.00	Wood H	6.00		1
20	Audubon	Sheyenne	230.00	230.00	Wood H	42.00		1
21	Winger (E 1/3)	Wilton	230.00	230.00	Alum Tower	18.00		1
22	Grand Forks (M 1/3)	Winnipeg	230.00	230.00	Wood H	27.00		1
23	Big Stone (N 1/3)	Hankinson	230.00	230.00	Wood H	23.00		1
24	Big Stone (S 1/4)	Blair	230.00	230.00	Wood H	15.00		1
25	Harvey	Coal Creek	230.00	230.00	Wood H	75.00		1
26	Balta	Harvey	230.00	230.00	Wood H	22.00		1
27	Rugby	Balta	230.00	230.00	Steel H	18.00		1
28	Wilton	Cass Lake	230.00	230.00	Steel H	19.00		1
29	Cass Lake	Boswell	230.00	230.00	Steel H	51.00		1
30	Hazel Creek	MN Valley	230.00	345.00	Steel Tower	5.00		1
31								
32		Total	115.00	115.00	Wood H	459.00		
33		Total	115.00	115.00	SWP	415.00		
34		Total	115.00	115.00	Steel Tower	4.00		
35		Total	69.00	69.00		209.00		
36					TOTAL	5,863.00		31

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 (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1		Total	41.60	41.60	SWP	3,762.00		
2		Total	41.60	41.60	Underground	1.00		
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32								
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34								
35								
36					TOTAL	5,863.00		31

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)	
	2,915,087	30,122,780	33,037,867					1
	92,821	1,047,704	1,140,525					2
	1,383,694	6,464,002	7,847,696					3
	487,170	4,014,089	4,501,259					4
		5,458,744	5,458,744					5
	490,734	2,421,900	2,912,634					6
	870,767	2,155,513	3,026,280					7
	154,916	2,003,641	2,158,557					8
	129,305	3,735,215	3,864,520					9
	617,532	8,185,871	8,803,403					10
	2,308,828	8,197,180	10,506,008					11
	2,677,317	23,273,915	25,951,232					12
								13
		2,024,040	2,024,040					14
		2,198,157	2,198,157					15
		1,273,238	1,273,238					16
	2,160	1,579,053	1,581,213					17
		4,726,800	4,726,800					18
		414,677	414,677					19
		1,690,121	1,690,121					20
		1,852,883	1,852,883					21
		913,195	913,195					22
		803,584	803,584					23
		867,131	867,131					24
		10,672,352	10,672,352					25
		4,433,901	4,433,901					26
		3,486,133	3,486,133					27
	489,732	4,363,737	4,853,469					28
	567,058	10,910,674	11,477,732					29
	47,577	704,552	752,129					30
								31
	9,395	11,066,559	11,075,954					32
	994,389	29,360,743	30,355,132					33
	15,584	187,124	202,708					34
		6,454,471	6,454,471					35
	14,260,492	301,041,440	315,301,932	6,072,451	1,869,813	49,879	7,992,143	36

Name of Respondent
Otter Tail Power Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
12/31/2016

Year/Period of Report
End of 2016/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)	
	6,426	103,905,088	103,911,514					1
		72,673	72,673					2
				6,072,451	1,869,813	49,879	7,992,143	3
								4
								5
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								35
	14,260,492	301,041,440	315,301,932	6,072,451	1,869,813	49,879	7,992,143	36

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 422.1 Line No.: 3 Column: m
Columns m, n, o, and p detail by line not available.

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 completed 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 (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Altered:						
2	Martin, ND	Anamoose, ND	0.70	Single pole	20.00	1	1
3							
4	Max Junction, ND	Douglas, ND	12.50	Single pole	20.00	1	1
5							
6	Urbank, MN	Parkers Prairie, MN	3.80	Single pole	23.00	1	1
7							
8							
9							
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43							
44	TOTAL		17.00		63.00	3	3

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 KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
10RT2	ACSR	3102	41	31,569	67,669	82,707	11,526	193,471	2
									3
10RT2	ACSR	Delta 3050	41	30,748	252,518	448,922	83,583	815,771	4
		framing							5
1/0 RT2	1/0 RT2	3102	41	52,801	308,238	232,531	-258,871	334,699	6
									7
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				115,118	628,425	764,160	-163,762	1,343,941	44

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 (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Transmission Subs 10,000 kva or higher				
2	Bemidji, MN - 115 kv - 63246	Transmission	115.00	69.00	13.20
3	Big Stone 230 kv - 620314	Transmission	230.00	115.00	13.80
4	Big Stone, SD Highway 12 - 63215	Transmission	115.00	41.60	
5	Big Stone South - 620417 - Not in Service	Transmission	345.00	230.00	345.00
6	Browns Valley, MN - 230 kv (Peever) - 63325	Transmission	230.00	41.60	
7	Buffalo, ND - 345 kv - 63258	Transmission	345.00	115.00	43.00
8	Canby, MN - 115 kv - 63211	Transmission	115.00	41.60	
9	Cass Lake, MN - 230 kv - 620447	Transmission	230.00	115.00	13.80
10	Cass Lake, MN - 115 kv - 63347	Transmission	115.00	69.00	41.60
11	Clearbrook, MN - 115 kv - 63241	Transmission	115.00	41.60	
12	Crookston, MN - 115 kv - 63249	Transmission	115.00	41.60	
13	Devils Lake, ND - East 115 kv - 63265	Transmission	115.00	41.60	
14	Devils Lake, ND - SW 115 kv - 224	Transmission	115.00	41.60	
15	Donaldson, MN - 115 kv - 63255	Transmission	115.00	41.60	
16	Fergus Falls, MN - Hoot Lake 115 kv - 63223	Transmission	115.00	43.80	
17	Fertile, MN - 115 kv - 63250	Transmission	115.00	41.60	
18	Finley, ND - Pickert 115 kv - 711	Transmission	230.00	72.00	41.60
19	Forman, ND - Forman 230 kv - 63363	Transmission	230.00	115.00	41.60
20	Hensel, ND - 115 kv - 63157	Transmission	115.00	72.00	43.80
21	Hetland, SD - 115 kv - 63209	Transmission	115.00	41.60	
22	Jamestown, ND - 345 kv - 63369	Transmission	345.00	115.00	43.00
23	Jamestown, ND - Peaking Plant 115 kv - 63272	Transmission	115.00	41.60	
24	Maple River, ND - 345 kv - 66792	Transmission	345.00	230.00	13.80
25	Mapleton, ND - 115 kv - 63203	Transmission	115.00	41.60	
26	Marietta, MN - 115 kv - 63213	Transmission	115.00	41.60	
27	Northwoods, MN - 115kv - 63282	Transmission	115.00	41.60	
28	Oakes, ND - 230 kv - 63362	Transmission	230.00	41.60	
29	Ortonville, MN - 115 kv - 63216	Transmission	115.00	41.60	
30	Pelican Rapids, MN - 115 k - 63234	Transmission	115.00	41.60	
31	Plummer, MN - 115kv - 7967	Transmission	115.00	41.60	
32	Rugby, ND - 230 kv - 63373	Transmission	230.00	115.00	13.80
33	Rugby, ND - 230 kv - 63373	Transmission	230.00	115.00	41.60
34	Spiritwood, ND	Transmission	115.00	41.60	
35	Toronto, SD - 115 kv - 63210	Transmission	115.00	41.60	
36	Wahpeton Inventory (came from Cass Lake)	Transmission	115.00	69.00	41.60
37	Wahpeton Inventory	Transmission	345.00	115.00	43.00
38	WAPA Summit, ND	Transmission	115.00	41.60	
39	Winger, MN 63238	Transmission	230.00	115.00	13.20
40	Subtotal:		6555.00	2763.40	807.40

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 (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1					
2	Transmission Subs Under 10,000 kva				
3	Colgate	Transmission	69.00	43.80	12.50
4	Green Valley	Transmission	67.00	41.60	
5	Lake Preston	Transmission	69.00	44.00	
6	St Vincent	Transmission	69.00	41.60	
7	Wahpeton Inventory	Transmission	69.00	41.60	
8	Total:		6898.00	2976.00	819.90
9					
10	Distribution Subs 10,000 kva or higher				
11	Bemidji, MN 25th Street	Distribution	69.00	12.50	
12	Bemidji, MN Airport	Distribution	41.60	12.50	
13	Bemidji, MN Nymore	Distribution	69.00	12.50	
14	Bemidji, MN Industrial Park	Distribution	69.00	12.50	
15	Bottineau, ND Downtown - Not In Service	Distribution	41.60	12.50	
16	Casselton, ND	Distribution	41.60	12.50	
17	Casselton, ND Ethonal plant	Distribution	115.00	12.50	
18	Clearbrook, MN Pipeline	Distribution	115.00	4.16	
19	Cooperstown, ND	Distribution	41.60	12.50	
20	Crookston, MN Parkview	Distribution	41.60	12.50	
21	Crookston, MN South Main	Distribution	41.60	12.50	
22	Dawson, Mn Dawson Mills	Distribution	115.00	12.50	
23	Devils Lake, ND Downtown	Distribution	41.60	4.16	
24	Enderlin, ND	Distribution	115.00	12.50	
25	Fairmount, ND	Distribution	115.00	12.50	
26	Fergus Falls, MN Edgetown	Distribution	115.00	12.50	
27	Fergus Falls, MN Hoot Lake	Distribution	115.00	12.50	
28	Fergus Falls, MN South East	Distribution	115.00	12.50	
29	Gwinner, ND	Distribution	115.00	12.50	
30	Harvey, ND Northwest	Distribution	115.00	12.50	
31	Itasca, MN Minnesota Pipeline	Distribution	115.00	4.16	
32	Jamestown, ND Downtown	Distribution	115.00	12.50	
33	Jamestown, ND North	Distribution	115.00	12.50	
34	Jamestown, ND Potato	Distribution	115.00	12.50	
35	Jamestown, ND Southwest	Distribution	41.60	12.50	
36	Lake Norden, SD Dairy	Distribution	41.60	12.50	
37	Lisbon, ND Town	Distribution	115.00	12.50	
38	Mahnomen, MN	Distribution	115.00	12.50	
39	Milbank, SD Northwest	Distribution	41.60	12.50	
40	Milbank, SD South	Distribution	41.60	12.50	

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 (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Morris, MN Northeast	Distribution	41.60	12.50	
2	Morris, MN South	Distribution	115.00	12.50	
3	Oakes, ND North	Distribution	41.60	12.50	
4	Parkers Prairie	Distribution	41.60	12.50	
5	Pelican Rapids, MN Turkey Plant	Distribution	115.00	12.50	
6	Perham, MN	Distribution	115.00	12.50	
7	Rosholt, SD	Distribution	41.60	12.50	
8	Rugby, ND South	Distribution	41.60	12.50	
9	Spiritwood, ND	Distribution	115.00	12.50	
10	Wahpeton Inventory	Distribution	115.00	12.50	
11	Wahpeton Inventory	Distribution	115.00	4.16	
12	Wahpeton Inventory	Distribution	41.60	12.50	
13	Wahpeton Inventory	Distribution	41.60	4.16	
14	Wahpeton, ND North 115 kv - 63230	Distribution	115.00	12.50	
15	Wahpeton, ND Northwest	Distribution	41.60	12.50	
16	Wheaton, MN South	Distribution	115.00	12.50	
17	Distribution Subtotal:		3757.40	533.30	
18					
19	Distribution Under 10,000 kva	Distribution			
20	Distribution Total		3757.40	533.30	
21	Transmission From Above		6898.00	2976.00	820.00
22	Transmission & Distribution		10655.40	3509.30	820.00
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (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
19	1					2
233	1					3
45	1					4
896	2					5
26	1					6
224	2					7
27	1					8
187	1					9
40	1					10
13	1					11
95	2					12
34	1					13
57	1					14
20	2					15
30	1					16
10	1					17
60	1					18
140	1					19
55	1					20
45	1					21
672	2					22
56	1					23
672	2					24
20	1					25
10	1					26
13	1					27
54	2					28
22	1					29
13	1					30
34	1					31
14	1					32
140	1					33
17	1					34
45	1					35
		1				36
		1				37
25	1					38
140	1					39
4203	43	2				40

SUBSTATIONS (Continued)

5. Show in columns (l), (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
						2
6	1					3
7	1					4
9	1					5
8	1					6
		1				7
4233	47	3				8
						9
						10
20	1					11
14	1					12
14	1					13
11	1					14
10	3					15
10	1					16
94	2					17
28	2					18
10	1					19
10	1					20
39	2					21
10	1					22
10	1					23
14	1					24
10	3					25
37	1					26
37	1					27
37	1					28
20	2					29
14	1					30
11	1					31
14	1					32
14	1					33
14	1					34
14	1					35
12	1					36
14	1					37
14	1					38
22	1					39
22	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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)	
12	1					1
12	3					2
10	3					3
10	1					4
10	1					5
28	2					6
10	1					7
10	1					8
84	2					9
		1				10
		1				11
		1				12
		1				13
24	2					14
20	2					15
12	1					16
842	58	4				17
						18
						19
842	58	4				20
4233	47	3				21
5075	105	7				22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 426 Line No.: 3 Column: a

Joint ownership, Otter Tail Power Company, 53.9%; Northwestern Public Service Company, 23.4%; Montana-Dakota Utilities Company, 22.7%. Expenses are shared on ownership percent basis. Accounts affected are regular accounts applicable to substations. None of the owners are associated companies.

Columns C, D, and E are reported in KVA.

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	Construction work in progress	Otter Tail Corporation	107	70,779
3	Expenditures for certain civic, political & relat	Otter Tail Corporation	426.4	24,150
4	Dividends declared - common stock	Otter Tail Corporation	438	38,552,899
5	Corporate allocated A&G expense	Otter Tail Corporation	See Note	9,932,843
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21	Printing, design & mailing services	Otter Tail Corporation	417	29,592
22	Other deductions	Otter Tail Corporation	426.5	547,719
23				
24	Printing, design & mailing services	BTD Manufacturing	417	328
25	Printing, design & mailing services	Northern Pipe Products	417	326
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	Non-power Goods or Services Provided by Affiliated			
2				

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)
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2016	Year/Period of Report 2016/Q4
FOOTNOTE DATA			

Schedule Page: 429 Line No.: 5 Column: a

Corporate allocated A&G expenses are allocated in accordance with Otter Tail Corporation's Corporate Cost Allocation Manual as approved by the Minnesota Public Utilities Commission, the North Dakota Public Service Commission, and the South Dakota Public Utilities Commission.

Schedule Page: 429 Line No.: 5 Column: c

The following accounts were charged:

500	\$	12,463
501		3,738
506		12,211
551		254
907		1,119
908		6,630
912		8,833
920		4,825,034
921		2,207,920
923		899,421
924		1,730
925		165,476
928		37,611
930.1		8,942
930.2		1,030,415
931		191,657
935		519,389

Total	\$	9,932,843

INDEX

<u>Schedule</u>	<u>Page No.</u>
Accrued and prepaid taxes	262-263
Accumulated Deferred Income Taxes	234
	272-277
Accumulated provisions for depreciation of	
common utility plant	356
utility plant	219
utility plant (summary)	200-201
Advances	
from associated companies	256-257
Allowances	228-229
Amortization	
miscellaneous	340
of nuclear fuel	202-203
Appropriations of Retained Earnings	118-119
Associated Companies	
advances from	256-257
corporations controlled by respondent	103
control over respondent	102
interest on debt to	256-257
Attestation	i
Balance sheet	
comparative	110-113
notes to	122-123
Bonds	256-257
Capital Stock	251
expense	254
premiums	252
reacquired	251
subscribed	252
Cash flows, statement of	120-121
Changes	
important during year	108-109
Construction	
work in progress - common utility plant	356
work in progress - electric	216
work in progress - other utility departments	200-201
Control	
corporations controlled by respondent	103
over respondent	102
Corporation	
controlled by	103
incorporated	101
CPA, background information on	101
CPA Certification, this report form	i-ii

<u>Schedule</u>	<u>Page No.</u>
Deferred	
credits, other	269
debits, miscellaneous	233
income taxes accumulated - accelerated amortization property	272-273
income taxes accumulated - other property	274-275
income taxes accumulated - other	276-277
income taxes accumulated - pollution control facilities	234
Definitions, this report form	iii
Depreciation and amortization	
of common utility plant	356
of electric plant	219
	336-337
Directors	105
Discount - premium on long-term debt	256-257
Distribution of salaries and wages	354-355
Dividend appropriations	118-119
Earnings, Retained	118-119
Electric energy account	401
Expenses	
electric operation and maintenance	320-323
electric operation and maintenance, summary	323
unamortized debt	256
Extraordinary property losses	230
Filing requirements, this report form	
General information	101
Instructions for filing the FERC Form 1	i-iv
Generating plant statistics	
hydroelectric (large)	406-407
pumped storage (large)	408-409
small plants	410-411
steam-electric (large)	402-403
Hydro-electric generating plant statistics	406-407
Identification	101
Important changes during year	108-109
Income	
statement of, by departments	114-117
statement of, for the year (see also revenues)	114-117
deductions, miscellaneous amortization	340
deductions, other income deduction	340
deductions, other interest charges	340
Incorporation information	101

<u>Schedule</u>	<u>Page No.</u>
Interest	
charges, paid on long-term debt, advances, etc	256-257
Investments	
nonutility property	221
subsidiary companies	224-225
Investment tax credits, accumulated deferred	266-267
Law, excerpts applicable to this report form	iv
List of schedules, this report form	2-4
Long-term debt	256-257
Losses-Extraordinary property	230
Materials and supplies	227
Miscellaneous general expenses	335
Notes	
to balance sheet	122-123
to statement of changes in financial position	122-123
to statement of income	122-123
to statement of retained earnings	122-123
Nonutility property	221
Nuclear fuel materials	202-203
Nuclear generating plant, statistics	402-403
Officers and officers' salaries	104
Operating	
expenses-electric	320-323
expenses-electric (summary)	323
Other	
paid-in capital	253
donations received from stockholders	253
gains on resale or cancellation of reacquired capital stock	253
miscellaneous paid-in capital	253
reduction in par or stated value of capital stock	253
regulatory assets	232
regulatory liabilities	278
Peaks, monthly, and output	401
Plant, Common utility	
accumulated provision for depreciation	356
acquisition adjustments	356
allocated to utility departments	356
completed construction not classified	356
construction work in progress	356
expenses	356
held for future use	356
in service	356
leased to others	356
Plant data	336-337
	401-429

<u>Schedule</u>	<u>Page No.</u>
Plant - electric	
accumulated provision for depreciation	219
construction work in progress	216
held for future use	214
in service	204-207
leased to others	213
Plant - utility and accumulated provisions for depreciation	
amortization and depletion (summary)	201
Pollution control facilities, accumulated deferred	
income taxes	234
Power Exchanges	326-327
Premium and discount on long-term debt	256
Premium on capital stock	251
Prepaid taxes	262-263
Property - losses, extraordinary	230
Pumped storage generating plant statistics	408-409
Purchased power (including power exchanges)	326-327
Reacquired capital stock	250
Reacquired long-term debt	256-257
Receivers' certificates	256-257
Reconciliation of reported net income with taxable income	
from Federal income taxes	261
Regulatory commission expenses deferred	233
Regulatory commission expenses for year	350-351
Research, development and demonstration activities	352-353
Retained Earnings	
amortization reserve Federal	119
appropriated	118-119
statement of, for the year	118-119
unappropriated	118-119
Revenues - electric operating	300-301
Salaries and wages	
directors fees	105
distribution of	354-355
officers'	104
Sales of electricity by rate schedules	304
Sales - for resale	310-311
Salvage - nuclear fuel	202-203
Schedules, this report form	2-4
Securities	
exchange registration	250-251
Statement of Cash Flows	120-121
Statement of income for the year	114-117
Statement of retained earnings for the year	118-119
Steam-electric generating plant statistics	402-403
Substations	426
Supplies - materials and	227

<u>Schedule</u>	<u>Page No.</u>
Taxes	
accrued and prepaid	262-263
charged during year	262-263
on income, deferred and accumulated	234
	272-277
reconciliation of net income with taxable income for	261
Transformers, line - electric	429
Transmission	
lines added during year	424-425
lines statistics	422-423
of electricity for others	328-330
of electricity by others	332
Unamortized	
debt discount	256-257
debt expense	256-257
premium on debt	256-257
Unrecovered Plant and Regulatory Study Costs	230