

THIS FILING IS

Item 1:  An Initial (Original) Submission OR  Resubmission No. \_\_\_\_\_

Form 1 Approved  
OMB No.1902-0021  
(Expires 11/30/2016)  
Form 1-F Approved  
OMB No.1902-0029  
(Expires 11/30/2016)  
Form 3-Q Approved  
OMB No.1902-0205  
(Expires 11/30/2016)



# 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** 2015/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/eforms/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/eforms/form-1/form-1.pdf> and <http://www.ferc.gov/docs-filing/eforms.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 18<sup>th</sup> 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).

**FERC FORM NO. 1/3-Q:  
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>2015/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> 12/31/2015

**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> 04/06/2016
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	Not applicable
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	Not applicable
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	Not applicable
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	Not applicable
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	Not applicable
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
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)  An Original  
(2)  A Resubmission

Date of Report  
(Mo, Da, Yr)  
12/31/2015

Year/Period of Report  
End of 2015/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
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) 12/31/2015	Year/Period of Report End of <u>2015/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> 12/31/2015	Year/Period of Report End of <u>2015/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	279,718
2			
3	Vice President, IT and Special Projects [1]	Rodney C.H. Scheel	129,423
4			
5	Vice President, Customer Service	Mark H. Helland	183,117
6			
7	Vice President, Administration	Thomas R. Brause	215,200
8			
9	Chief Financial Officer	George D. Bell	201,497
10			
11	Vice President, Energy Supply	Jan P. Rudolf	185,742
12			
13	President, Utility	Timothy J. Rogelstad	325,000
14			
15	General Counsel & Secretary	Jennifer O. Smestad	174,543
16			
17	Vice President, Asset Management	JoAnn M. Thompson	154,125
18			
19	Vice President, Public Relations	Cris M. Oehler	153,008
20			
21	Vice President, Planning and Strategy	Bradley E. Tollerson	176,700
22			
23	Treasurer * **	Kevin G. Moug	242,440
24			
25	Assistant Secretary * **	George A. Koeck	225,380
26			
27	Assistant Treasurer * ** [2]	Brian Carlson	40,556
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29	Assistant Treasurer * ** [3]	Suzanne Allen	63,672
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36	[1] Retired effective 09/01/2015.		
37	[2] Removed effective 05/18/2015.		
38	[3] Effective 05/18/2015.		
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40	* This individual is an employee of		
41	Otter Tail Corporation.		
42			
43	** Portion of salary allocated to the Utility.		
44			

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	Edward J. McIntyre, Director [1]	Fargo, North Dakota
3		
4	George A. Koeck, Director, Assistant Secretary	Fargo, North Dakota
5		
6	Charles S. MacFarlane, Director, and CEO, Utility	Fergus Falls, Minnesota
7		
8	Kevin Moug, Director, Treasurer	Fargo, North Dakota
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10	Timothy J. Rogelstad, Director	Fergus Falls, Minnesota
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12	John Abbott, Director [2]	Fargo, North Dakota
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45	[1] Removed effective 04/13/2015.	
46	[2] Effective 04/13/2015.	
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**INFORMATION ON FORMULA RATES**  
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?  Yes  
 No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	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;001
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
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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)  
12/31/2015

Year/Period of Report  
End of 2015/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	201503135220	03/13/2015	ER15-1276-000	Annual Informational Attachment O Filing	MISO FERC Electric Tariff
2					
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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 12/31/2015	Year/Period of Report End of <u>2015/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) 12/31/2015	Year/Period of Report 2015/Q4
Otter Tail Power Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. None.
2. None.
3. None.
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-15-411 dated July 10, 2015.
7. None.
8. The average annual increase for full-time nonunion employees was 2.98% effective April 1, 2015. Wages for Local Union 1570 were increased by 3.0% effective September 1, 2015. Wages for Local Unions 949, 524, 239, and 203 were increased by 3.0% effective November 1, 2015.
9. None.
10. Otter Tail Power Company is a subsidiary of Otter Tail Corporation.
11. (Reserved.)
12. None.
13. Edward J. McIntyre, removed as Director, effective April 13, 2015; John Abbott appointed as Director, effective April 13, 2015; Brian Carlson removed as Assistant Treasurer, effective May 18, 2015; Suzanne Allen elected as Assistant Treasurer, effective May 18, 2015. Rodney C. H. Scheel, Vice President, IT and Special Projects, retired effective 9/1/2015.
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)
<b>1</b>	<b>UTILITY PLANT</b>			
2	Utility Plant (101-106, 114)	200-201	1,820,763,015	1,545,112,170
3	Construction Work in Progress (107)	200-201	64,117,181	240,169,972
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,884,880,196	1,785,282,142
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	666,949,303	659,193,694
6	Net Utility Plant (Enter Total of line 4 less 5)		1,217,930,893	1,126,088,448
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)		1,217,930,893	1,126,088,448
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
<b>17</b>	<b>OTHER PROPERTY AND INVESTMENTS</b>			
18	Nonutility Property (121)		664,511	429,511
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)		102,343	195,977
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		903,538	840,135
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)		1,670,392	1,465,623
<b>33</b>	<b>CURRENT AND ACCRUED ASSETS</b>			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		11,300	10,300
36	Special Deposits (132-134)		1,847,407	2,749,931
37	Working Fund (135)		16,940	19,055
38	Temporary Cash Investments (136)		0	148,179
39	Notes Receivable (141)		50,000	50,000
40	Customer Accounts Receivable (142)		19,172,775	19,737,127
41	Other Accounts Receivable (143)		8,477,335	12,534,153
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		855,596	824,670
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		11,175	44,859
45	Fuel Stock (151)	227	12,309,141	9,624,428
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	19,118,093	18,423,124
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	59,417	0

**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)		932,933	426,614
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)		16,035,137	19,110,252
62	Miscellaneous Current and Accrued Assets (174)		5,698	21,586
63	Derivative Instrument Assets (175)		0	257,105
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	4
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		77,191,755	82,332,047
68	<b>DEFERRED DEBITS</b>			
69	Unamortized Debt Expenses (181)		2,850,815	3,079,532
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	4,304,770	4,642,624
72	Other Regulatory Assets (182.3)	232	140,415,631	147,143,701
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)		-11,351	-27,466
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	0	144,583
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)		1,890,097	2,241,075
82	Accumulated Deferred Income Taxes (190)	234	138,860,665	107,452,075
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		288,310,627	264,676,124
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,585,103,667	1,474,562,242

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) 12/31/2015	Year/Period of Report 2015/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, 2014	\$ 426,614
January 31, 2015	1,657,677
February 28, 2015	1,390,908
March 31, 2015	1,200,336
April 30, 2015	2,546,152
May 31, 2015	2,269,520
June 30, 2015	1,993,564
July 31, 2015	1,755,563
August 31, 2015	1,477,629
September 30, 2015	1,199,694
October 31, 2015	954,642
November 30, 2015	676,708
December 31, 2015	932,933
 13-month average for rate-making	 \$ 1,421,688

**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	339,988,966	296,261,391
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	158,534,255	147,114,517
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)	-1,676,110	-1,853,222
16	Total Proprietary Capital (lines 2 through 15)		496,847,611	441,523,186
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	87,460
28	Accumulated Provision for Injuries and Damages (228.2)		577,000	577,000
29	Accumulated Provision for Pensions and Benefits (228.3)		135,021,435	137,888,376
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		8,083,769	7,722,821
35	Total Other Noncurrent Liabilities (lines 26 through 34)		143,682,204	146,275,657
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		21,005,840	0
38	Accounts Payable (232)		53,590,862	64,637,846
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		1,927,904	3,598,930
41	Customer Deposits (235)		1,090,716	1,142,378
42	Taxes Accrued (236)	262-263	13,310,233	12,180,596
43	Interest Accrued (237)		6,846,044	6,827,000
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

**COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)** (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,248,513	1,264,709
48	Miscellaneous Current and Accrued Liabilities (242)		4,876,439	686,723
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		198,754	14,229,954
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		104,095,305	104,568,136
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	24,506,045	26,384,039
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	11,595,907	974,660
60	Other Regulatory Liabilities (254)	278	3,971,465	3,934,293
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		336,771,334	287,721,110
64	Accum. Deferred Income Taxes-Other (283)		18,633,796	18,181,161
65	Total Deferred Credits (lines 56 through 64)		395,478,547	337,195,263
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,585,103,667	1,474,562,242

## 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	399,535,911	402,135,463		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	231,850,778	239,585,126		
5	Maintenance Expenses (402)	320-323	28,176,032	33,223,158		
6	Depreciation Expense (403)	336-337	41,441,421	41,002,229		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	146,067	65,640		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	1,496,906	1,294,748		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	44,939	49,025		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		740,192	1,101,302		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)			33,411		
13	(Less) Regulatory Credits (407.4)		778,134	549,480		
14	Taxes Other Than Income Taxes (408.1)	262-263	13,504,765	12,599,569		
15	Income Taxes - Federal (409.1)	262-263	-1,845,914	-2,411,627		
16	- Other (409.1)	262-263	-394,453	-466,417		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	24,176,441	8,304,094		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	6,780,347	-5,390,442		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,877,994	-1,903,783		
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)		29	100		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		335,743	478,263		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		330,236,413	337,795,600		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		69,299,498	64,339,863		

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 purchases, 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)	
399,535,911	402,135,463					2
						3
231,850,778	239,585,126					4
28,176,032	33,223,158					5
41,441,421	41,002,229					6
146,067	65,640					7
1,496,906	1,294,748					8
44,939	49,025					9
740,192	1,101,302					10
						11
	33,411					12
778,134	549,480					13
13,504,765	12,599,569					14
-1,845,914	-2,411,627					15
-394,453	-466,417					16
24,176,441	8,304,094					17
6,780,347	-5,390,442					18
-1,877,994	-1,903,783					19
						20
						21
29	100					22
						23
335,743	478,263					24
330,236,413	337,795,600					25
69,299,498	64,339,863					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)		69,299,498	64,339,863		
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)		777,666	950,932		
34	(Less) Expenses of Nonutility Operations (417.1)		534,579	554,609		
35	Nonoperating Rental Income (418)		56,081	55,509		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		208,005	236,959		
38	Allowance for Other Funds Used During Construction (419.1)		1,302,804	1,543,423		
39	Miscellaneous Nonoperating Income (421)		5,086,141	4,098,851		
40	Gain on Disposition of Property (421.1)		9,258			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		6,905,376	6,331,065		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			12,771		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		375,508	464,813		
46	Life Insurance (426.2)					
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		187,404	215,069		
49	Other Deductions (426.5)		104,201	849,539		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		667,113	1,542,192		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	7,404	6,787		
53	Income Taxes-Federal (409.2)	262-263	2,077,088	2,536,661		
54	Income Taxes-Other (409.2)	262-263	394,461	466,419		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	633,974	-584,063		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	316,413	302,745		
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)		2,796,514	2,123,059		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		3,441,749	2,665,814		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		23,931,900	22,774,908		
63	Amort. of Debt Disc. and Expense (428)		388,084	394,099		
64	Amortization of Loss on Reaquired Debt (428.1)		350,978	362,452		
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)		423,148	479,398		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		723,318	689,294		
70	Net Interest Charges (Total of lines 62 thru 69)		24,370,792	23,321,563		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		48,370,455	43,684,114		
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)		48,370,455	43,684,114		

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		146,601,836	138,400,473
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)		48,370,455	43,684,114
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess hydro licensing amortization		-64,511	( 74,482)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-64,511	( 74,482)
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			-36,950,717	( 35,408,269)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-36,950,717	( 35,408,269)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		157,957,063	146,601,836
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39	Amortization reserve, federal (Account 215.1)		577,192	512,681
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)		577,192	512,681
	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)		577,192	512,681
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		158,534,255	147,114,517
	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)	48,370,455	43,684,114
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	41,587,487	41,067,869
5	Amortization	1,929,930	1,737,872
6	Vehicle depreciation allocated to various operating accounts	1,807,939	1,737,917
7			
8	Deferred Income Taxes (Net)	18,094,269	13,090,716
9	Investment Tax Credit Adjustment (Net)	-1,877,994	-1,903,783
10	Net (Increase) Decrease in Receivables	-1,008,629	-1,543,420
11	Net (Increase) Decrease in Inventory	-3,379,682	-1,337,538
12	Net (Increase) Decrease in Allowances Inventory	-59,417	
13	Net Increase (Decrease) in Payables and Accrued Expenses	-19,326,882	8,115,787
14	Net (Increase) Decrease in Other Regulatory Assets	7,065,924	-53,467,791
15	Net Increase (Decrease) in Other Regulatory Liabilities	37,172	267,029
16	(Less) Allowance for Other Funds Used During Construction	1,302,804	1,543,423
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other: (Increase) decrease in noncurrent assets and deferred debits	509,677	1,430,612
19	Other: Increase(decrease) in noncurrent liabilities & deferred credits	8,204,906	36,492,949
20	Other: (Increase) decrease in other current assets	2,841,793	-290,312
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	103,494,144	87,538,598
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-136,779,717	-150,846,464
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-235,000	-178,600
30	(Less) Allowance for Other Funds Used During Construction	-1,302,804	-1,543,423
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-135,711,913	-149,481,641
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	5,694,409	-1,330,000
50	Net (Increase ) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	-5,897,233	1,596,000
53	Other: (Increase) decrease in funds on deposit with trustee	902,524	758,649
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-135,012,213	-148,456,992
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		150,000,000
62	Preferred Stock		
63	Common Stock		
64	Other: debt issuance expense	-159,367	-686,328
65			
66	Net Increase in Short-Term Debt (c)	21,005,840	
67	Other: change in checks written in excess of cash	3,745,444	-4,744,224
68	Other: proceeds from capital infusions	43,727,575	44,000,000
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	68,319,492	188,569,448
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-40,900,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		-51,194,606
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-36,950,717	-35,408,269
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	31,368,775	61,066,573
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-149,294	148,179
87			
88	Cash and Cash Equivalents at Beginning of Period	177,534	29,355
89			
90	Cash and Cash Equivalents at End of period	28,240	177,534

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) 12/31/2015	Year/Period of Report 2015/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, and derivative 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 12/31/2015	Year/Period of Report End of <u>2015/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 Recquired Debt, and 257, Unamortized Gain on Recquired 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) 12/31/2015	Year/Period of Report 2015/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.

Cash Equivalents	\$ <u>2015</u> 0	\$ <u>2014</u> 177,534
Reconciliation	<u>2015</u>	<u>2014</u>
Cash – Account 131 (Line 35, Page 110)	\$ 11,300	\$ 10,300
Working Fund – Account 135 (Line 37, Page 110)	16,940	19,055
Cash Equivalent – Account 136 (Above)	<u>0</u>	<u>148,179</u>
	\$ 28,240	\$ 177,534

Otter Tail Power Company

Notes to Financial Statements

For the years ended December 31, 2015 and 2014

## 1. Summary of Significant Accounting Policies

### Organization and Operations

Otter Tail Power Company was incorporated in 1907 under the laws of the State of Minnesota. In 2001, the name was changed to “Otter Tail Corporation” to more accurately represent the broader scope of consolidated operations and the name Otter Tail Power Company (OTP) was retained for use by the electric utility.

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 421 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, 2015 OTP served 131,149 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>	2015	2014
Accounts Receivable	\$ 11	\$ 45
Accounts Payable	1,928	3,599
Operating Revenues	92	114
Other Operation and Maintenance Expenses	10,868	9,200

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) 12/31/2015	Year/Period of Report 2015/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 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) Accounting Standards Codification (ASC) 980, *Regulated Operations* (ASC 980). 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 \$723,000 in 2015 and \$689,000 in 2014. 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 service lives of the properties (5 to 70 years). Such provisions as a percent of the average balance of depreciable electric utility property were 2.61% in 2015 and 2.89% in 2014. 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 transmission lines and two additional major transmission lines under construction. The following table provides ownership percentages

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and amounts included in OTP's December 31, 2015 and 2014 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		
<b>December 31, 2015</b>					
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 <sup>I</sup>	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 <sup>I</sup>	50.0%	--	14,210	--	14,210
Big Stone South to Ellendale 345 kV line <sup>I</sup>	50.0%	--	8,335	--	8,335
<b>December 31, 2014</b>					
Big Stone Plant	53.9%	\$ 143,746	\$ 160,809	\$ (86,211)	\$ 218,344
Coyote Station	35.0%	163,824	1,725	(99,364)	66,185
Fargo-Monticello 345 kV line	14.2%	36,240	38,165	(737)	73,668
Brookings-Southeast Twin Cities 345 kV line <sup>I</sup>	4.8%	16,077	8,143	(132)	24,088
Bemidji-Grand Rapids 230 kV line	14.8%	16,331	--	(889)	15,442
Big Stone South to Brookings 345 kV line <sup>I</sup>	50.0%	--	6,623	--	6,623
Big Stone South to Ellendale 345 kV line <sup>I</sup>	50.0%	--	6,232	--	6,232

<sup>I</sup>MISO 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 to be paid by the Coyote Station owners under the LSA will reflect 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.

Under the LSA, all development period costs of the Coyote Creek coal mine incurred during the development period will be recovered from the Coyote Station owners over the full term of the production period, which commences with the initial delivery of coal to Coyote Station (anticipated in May 2016), by being included in the cost of production. The development fee and the capital charge incurred during the development period will be recovered from the Coyote Station owners over the first 52 months of the production period by being included in the cost of production during those months. The LSA was amended on March 16, 2015 to provide, among other things, that during any period between December 31, 2016 and any subsequent date on which CCMC makes initial delivery of coal, the Coyote Station owners will pay the following costs of production as advance payments for lignite: depreciation and amortization charges on capital assets and CCMC's obligations under its loans and leases. In addition, if the LSA terminates prior to

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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. OTP's 35% share of development period costs, development fees and capital charges incurred by CCMC through December 31, 2015 is \$56.1 million. 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, 2015 could be as high as \$56.1 million.

#### Income Taxes

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. 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, *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 to the financial statements regarding the OTP's accounting for uncertain tax positions.

OTP also is required to assess the reliability 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.

In the case of derivative instruments, such as OTP's forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with ASC Topic 815, *Derivatives and Hedging* (ASC 815). Gains and losses on forward energy contracts subject to regulatory treatment, if any, are deferred and recognized on a net basis in revenue in the period realized. 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.

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### Investments

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

<i>(in thousands)</i>	2015	2014
Cost Method – Economic Development Loan Pools	\$ 81	\$ 174
Equity Method – Partnership	22	22
Total Investments	\$ 103	\$ 196

### 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. The three levels defined by the hierarchy and examples of each level are as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange (NYMEX).

Level 2 – Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

Level 3 – Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation and may include complex and subjective models and forecasts.

The following tables present, for each of the hierarchy levels, OTP's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2015 and December 31, 2014:

<b>December 31, 2015</b> <i>(in thousands)</i>	Level 1	Level 2	Level 3
<b>Liabilities:</b>			
Derivative Liabilities – Forward Gasoline Purchase Contracts		\$ 199	
<b>December 31, 2014</b> <i>(in thousands)</i>			
<b>Assets:</b>			
Current Assets – Other:			
Forward Energy Contracts			\$ 257
<b>Liabilities:</b>			
Derivative Liabilities – Forward Gasoline Purchase Contracts		\$ 342	
Derivative Liabilities – Forward Energy Contracts			\$13,888

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.

Fair values for OTP's forward energy contracts with delivery points that are not at an active trading hub included in Level 3 of the fair value hierarchy in the table above as of December 31, 2014, were based on prices indexed to observable prices at an active trading hub. Prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads were based on historical spreads. The December 31, 2014 Level 3 forward electric basis spreads ranged from \$2.50 to \$7.97 per megawatt-hour under the active trading hub price. The weighted average price was \$34.95 per megawatt-hour.

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In the table above, the fair value of the Level 3 forward energy contracts in derivative asset and derivative liability positions as of December 31, 2014 were related to power purchase contracts where OTP intends to take or has taken physical delivery of the energy under the contract. When OTP takes physical delivery of the energy purchased under these contracts the costs incurred are subject to recovery in base rates and through fuel clause adjustments. Any derivative assets or liabilities and related gains or losses recorded as a result of the fair valuation of these power purchase contracts were not and will not be realized and are 100% offset by regulatory liabilities and assets related to fuel clause adjustment treatment of purchased power costs. Therefore, the net impact of any recorded fair valuation gains or losses related to these contracts on OTP's net income is \$0. When energy was or is delivered under these contracts, they were or will be settled at the original contract price and any fair valuation gains or losses and related derivative assets or liabilities recorded over the life of the contracts were or will be reversed along with any offsetting regulatory liabilities or assets. Because of regulatory accounting treatment, any price volatility related to the fair valuation of these contracts had no impact on OTP's reported net income for the years ended December 31, 2015 and 2014.

The following table presents changes in Level 3 forward energy contract derivative asset and liability fair valuations for:

<i>(in thousands)</i>	2015	2014
Forward Energy Contracts – Fair Values Beginning of Period	\$ (13,631)	\$ (11,341)
Less: Amounts Reversed on Settlement of Contracts Entered into in Prior Periods	4,492	2,785
Changes in Fair Value of Contracts Entered into in Prior Periods	(6,470)	166
Cumulative Fair Value Adjustments of Contracts Entered into in Prior Years at End of Period	(15,609)	(8,390)
Net Decrease in Value of Open Contracts Entered into in Current Period	--	(5,241)
Reclassification of Derivative Liability Fair Values for Contracts Designated as Normal Purchases effective October 1, 2015	15,609	
Forward Energy Contracts – Net Derivative Liability Fair Values End of Period	\$ --	\$ (13,631)

#### Inventories

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

#### Intangible Assets

In the first quarter of 2015, OTP began purchasing emission allowances to apply against sulfur dioxide emissions from its Hoot Lake Plant. The cost of unused emission allowances is included in investments and other assets on OTP's December 31, 2015 balance sheet. The following table presents a reconciliation of OTP's emission allowances balance for the year ended December 31, 2015:

<i>(in thousands)</i>	2015
Emission Allowances Beginning Balance	\$ --
Allowances Purchased	168
Allowances Used	(109)
Emission Allowances Ending Balance	\$ 59

#### Supplemental Disclosures of Cash Flow Information

<i>(in thousands)</i>	As of December 31,	
	2015	2014
Noncash Investing Activities:		
Transactions Related to Capital Additions not Settled in Cash	\$ 19,004	\$ 19,207
Cash Paid During the Year for:		
Interest (net of amount capitalized)	\$ 23,613	\$ 19,992
Income Tax Payments	\$ --	\$ 55

#### New Accounting Standards

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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 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. OTP is currently reviewing ASU 2014-09, identifying key impacts to its businesses, reviewing revenue streams and contracts to determine areas where the amendments in ASU 2014-09 will be applicable and evaluating transition options. OTP does not plan to adopt the updated guidance prior to January 1, 2018.

ASU 2015-03—In April 2015, the FASB issued ASU No. 2015-03, *Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs (ASU 2015-03)*, which requires debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. ASU 2015-03 will become effective for interim and annual reporting periods beginning after December 15, 2015 with early adoption permitted. OTP will apply the updated standards in ASU 2015-03 to its financial statements beginning in the first quarter of 2016. As of December 31, 2015, the balance of OTP's unamortized debt issuance costs related to its outstanding long-term debt was approximately \$2.1 million.

ASU 2015-07—In May 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)*, which eliminates the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share (NAV) practical expedient. The new standard is effective for reporting periods beginning after December 31, 2015, with early adoption permitted. Once adopted, the update is required to be applied on a retrospective basis for all periods presented. OTP adopted the updates in ASU 2015-07 in December 2015. The adoption of the updates in ASU 2015-07 did not have a material impact on OTP's financial statements other than the disclosure and presentation of certain investments of OTP's pension plan that are measured using the NAV practical expedient.

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.

Subsequent Events—Management has evaluated the impact of events occurring after December 31, 2015 up to March 10, 2016, the date the Company's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 6, 2016. 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 2015 and 2014.

### Major Capital Expenditure Projects

Big Stone Plant Air Quality Control System (AQCS)—The South Dakota Department of Environmental and Natural Resources determined the Big Stone Plant is subject to Best-Available Retrofit Technology (BART) requirements of the Clean Air Act, based on air dispersion modeling indicating that Big Stone Plant's emissions reasonably contribute to visibility impairment in

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national parks and wilderness areas in Minnesota, North Dakota, South Dakota and Michigan. OTP completed construction and testing of the BART-compliant AQCS at Big Stone Plant in the fourth quarter of 2015 and placed the AQCS into commercial operation on December 29, 2015. The capitalized cost of the project as of December 31, 2015 was approximately \$367 million (OTP's 53.9% share was approximately \$198 million).

Fargo–Monticello 345 kiloVolt (kV) Capacity Expansion 2020 (CapX2020) Project (the Fargo Project)—OTP has invested approximately \$81.5 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 \$26.2 million and has a 4.8% ownership interest in this 250-mile transmission line. The MISO granted unconditional approval of the Brookings Project as a Multi-Value Project (MVP) under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (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. The final segments of this line were energized on March 26, 2015.

The Big Stone South – Brookings MVP and CapX2020 Project—This 345 kV transmission line, currently under construction, will extend approximately 70 miles between a proposed substation near Big Stone City, South Dakota and the Brookings County Substation near Brookings, South Dakota. OTP and Northern States Power – MN (NSP MN), a subsidiary of Xcel Energy Inc., jointly developed this project. MISO approved this project as an MVP under the MISO Tariff in December 2011. A Notice of Intent to Construct Facilities (NICF) was filed with the SDPUC on February 29, 2012. The SDPUC approved the certification for the northern portion of the route on April 9, 2013 and granted approval of a route permit for the southern portion of the line on February 18, 2014. On August 1, 2014 OTP and NSP MN entered into agreements to construct the project. This line is expected to be in service in fall 2017. Construction began on this line in the third quarter of 2015.

The Big Stone South – Ellendale MVP—This is a proposed 345 kV transmission line that will extend 160 to 170 miles between a proposed substation near Big Stone City, South Dakota and a proposed substation near Ellendale, North Dakota. OTP is jointly developing this project with Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc. (MDU). MISO approved this project as an MVP under the MISO Tariff in December 2011. OTP and MDU jointly filed an NICF with the SDPUC in March of 2012. On August 25, 2013 the NDPSC granted Certificates of Public Convenience and Necessity to OTP and MDU for ten miles of the proposed line to be built in North Dakota. On July 10, 2014 the NDPSC approved a Certificate of Corridor Compatibility and a route permit for the North Dakota section of the proposed line. On August 22, 2014 the SDPUC issued an order approving the route permit for the South Dakota section of the proposed line. A route permit amendment to shift a portion of the route in North Dakota was approved by the NDPSC on December 16, 2015. On June 12, 2015 OTP and MDU entered into agreements to construct the project. This project is expected to be completed in 2019.

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.

#### Big Stone II Project

On June 30, 2005 OTP and a coalition of six other electric providers entered into several agreements for the development of a second electric generating unit, named Big Stone II, at the site of the existing Big Stone Plant near Milbank, South Dakota. On September 11, 2009 OTP announced its withdrawal—both as a participating utility and as the project's lead developer—from Big Stone II. On November 2, 2009, the remaining Big Stone II participants announced the cancellation of the Big Stone II project. Recovery in Minnesota and North Dakota of amounts OTP had invested in the Big Stone II project at the time of its withdrawal is discussed below under the respective jurisdictional sections of this report.

#### 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

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10%, respectively. Reagent costs were incurred in 2015 when the Big Stone Plant AQCS and Coyote Station and Hoot Lake Plant Mercury and Air Toxics Standards (MATS) projects went into service.

Minnesota

2010 General Rate Case—OTP’s most recent 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 was set at 8.61%, and its allowed rate of return on equity was set at 10.74%.

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 increase in annual revenue of approximately \$19.3 million, or 9.8%, based on 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. Through this rate case proceeding, OTP is proposing to recover, in base rates, revenue currently subject to recovery under Minnesota TCR and Environmental Cost Recovery (ECR) riders.

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 Minnesota Department of Commerce (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 October 10, 2013 the MPUC approved OTP’s 2012 financial incentive request for \$2.7 million as well as its request for an updated surcharge rate to be implemented on November 1, 2013. On September 26, 2014 the MPUC approved OTP’s 2013 financial incentive request for \$4.0 million, an updated surcharge rate to be effective October 1, 2014, as well as a change to the carrying charge to be equal to the short term cost of debt set in OTP’s most recent general rate case.

OTP recognized a financial incentive for 2014 of \$3.0 million due, in part, to the MPUC lowering the MNCIP financial incentive from approximately \$0.09 per kwh saved for 2013-2015 to \$0.07 per kwh saved for 2014-2016. Additionally, OTP saved approximately 2 million less kwhs in 2014 compared with 2013 under conservation improvement programs in Minnesota. 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 has recognized a financial incentive of \$4.2 million. The 2015 MNCIP program resulted in approximately a 39% increase in energy savings compared to 2014 program results.

Transmission Cost Recovery (TCR) Rider—The Minnesota Public Utilities Act (the 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 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. 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.

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MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from other MISO customers. On March 26, 2012 the MPUC approved an update to OTP's Minnesota TCR rider along with an all-in method for MISO regional cost allocations in which OTP's retail customers would be responsible for the entire investment OTP made in transmission facilities that qualify for regional cost allocation under the MISO Tariff, with an offsetting credit for revenues received from other MISO utilities under the MISO Tariff for projects included in the TCR. OTP's updated Minnesota TCR rider went into effect April 1, 2012.

OTP filed an annual update to its Minnesota TCR rider on February 7, 2013 to include three new projects as well as updated costs associated with existing projects. In a written order issued on March 10, 2014, the MPUC approved OTP's 2013 TCR rider update but found capitalized internal costs, costs in excess of CON estimates and a carrying charge ineligible for recovery through the TCR rider. These items were removed from OTP's Minnesota TCR rider effective March 1, 2014. OTP will be allowed to seek recovery of the capitalized internal costs and costs in excess of CON estimates in a future rate case. In response to the MPUC's approval of OTP's annual TCR update, OTP submitted a compliance filing in April 2014 reflecting the TCR rider revenue requirements changes relating to the MPUC's ruling and requesting no rate change be implemented at the time. The MPUC approved OTP's compliance filing on June 19, 2014. 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 \$7.2 million with a proposed effective date of April 1, 2016. A supplemental filing to the update was made on December 21, 2015 to address an issue surrounding the proration of accumulated deferred income taxes.

Environmental Cost Recovery (ECR) Rider—On December 18, 2013 the MPUC granted approval of OTP's Minnesota ECR rider for recovery of OTP's Minnesota jurisdictional share of the revenue requirements of its investment in the Big Stone Plant AQCS effective January 1, 2014. The ECR rider recoverable revenue requirements include a current return on the project's Construction Work in Progress (CWIP) balance at the level approved in OTP's most recent general rate case. OTP filed its 2014 annual update on July 31, 2014, requesting a \$4.1 million annual increase in the rider from \$6.1 million to \$10.2 million. The MPUC approved OTP's ECR rider annual update request on November 24, 2014, effective December 1, 2014. Because the effective date was two months behind the anticipated implementation date for the updated rate and a portion of the requested increase had been collected under the initial rate, the approved updated rate is based on a revenue requirement of \$9.8 million. OTP filed its 2015 annual update on July 31, 2015, with a request to keep the same rate in place. On December 21, 2015 OTP filed a supplemental filing with updated financial information.

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 will be reviewed in OTP's 2016 general rate case in Minnesota and considered for recovery either through the FCA rider or general rates. These costs are currently being expensed as incurred.

Big Stone II Project Cost Recovery—OTP requested recovery of the Minnesota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in Minnesota on April 2, 2010. In a written order issued on April 25, 2011, the MPUC authorized recovery of the Minnesota portion of Big Stone II generation development costs from Minnesota ratepayers over a 60-month recovery period which began on October 1, 2011. The amount of Big Stone II generation costs incurred by OTP that were deemed recoverable from Minnesota ratepayers as part of the rates established in that proceeding was \$3.2 million. Because OTP was not allowed to earn a return on these deferred costs over the 60-month recovery period, the recoverable amount of \$3.2 million was discounted to its present value of \$2.8 million using OTP's incremental borrowing rate, in accordance with ASC Topic 980, *Regulated Operations* (ASC 980) accounting requirements. Transmission-related project costs of \$3.2 million remained in CWIP as active project costs at the time of the order.

Approximately \$0.4 million of the total Minnesota jurisdictional share of Big Stone II transmission costs were transferred to the Big Stone South - Brookings MVP transmission line project in the first quarter of 2013. The remaining transmission costs, along with accumulated AFUDC, were transferred from CWIP to a regulatory asset account in May 2013, based on recovery granted in the April 25, 2011 order. Because OTP was not allowed to earn a return on these deferred costs over their anticipated recovery period, the recoverable amount of approximately \$3.5 million was discounted to its present value using OTP's incremental borrowing rate. In May 2013, OTP recorded a charge of \$0.7 million related to the discount in accordance with ASC 980 accounting requirements. In June 2014, OTP recorded an additional discount of \$0.3 million to reflect changes in the end date of the anticipated recovery period from September 2020 to December 2022. In accordance with ASC 980, OTP continues to monitor the assumptions used in the discounting of the Minnesota Big Stone II Transmission costs. A reversal of \$0.2 million of the discount previously recorded was made in

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December 2015 to reflect updated information.

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## 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 with a return on investment at the level approved in OTP’s most recent general rate case. On December 28, 2012 OTP submitted an annual update to the NDRRA with a proposed effective date of April 1, 2013. The update resulted in a rate reduction, so the NDPSC did not issue an order suspending the rate change. Consequently, pursuant to statute, OTP was allowed to implement updated rates effective April 1, 2013 with the NDPSC granting subsequent approval of the updated rates on July 10, 2013. The NDPSC approved OTP’s 2013 annual update to the NDRRA on March 12, 2014 with an effective date of April 1, 2014, which resulted in a 13.5% reduction in the NDRRA rate. 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. In each instance the NDRRA rates have been based on a return on investment at the rate of return approved in OTP’s last general rate case. OTP submitted its 2015 annual update to the NDRRA rider rate on December 31, 2015 with a requested implementation date of April 1, 2016.

**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 2013 annual update to its TCR rider rate on December 30, 2013 with an effective date of January 1, 2014. 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 will incur beginning January 1, 2016. These new costs are associated with OTP’s load connected to the transmission system of Central Power Electric Cooperative (CPEC) that will become subject to SPP transmission-related charges when CPEC transmission assets are 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.

**Environmental Cost Recovery Rider**— On February 8, 2013 OTP filed a request with the NDPSC for an ECR rider to recover OTP’s North Dakota jurisdictional share of the revenue requirements associated with its investment in the Big Stone Plant AQCS. On December 18, 2013 the NDPSC approved OTP’s North Dakota ECR rider based on revenue requirements through the 2013 calendar year and thereafter, with rates effective for bills rendered on or after January 1, 2014. The ECR provides for a current return on CWIP and a return on investment at the level approved in OTP’s most recent general rate case. On March 31, 2014 OTP filed an annual update to its North Dakota ECR rider rate. The update included a request to increase the ECR rider rate from 4.319% of base rates to 7.531% of base rates. The NDPSC approved OTP’s 2014 ECR rider annual update request on July 10, 2014 with an August 1, 2014 implementation date. 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% of base rates 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.

**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.

**Big Stone II Project**—In an order issued June 25, 2010, the NDPSC authorized recovery of Big Stone II development costs from North Dakota ratepayers. The North Dakota’s jurisdictional share of Big Stone II generation costs incurred by OTP was \$4.1 million. OTP included in its total recovery amount a carrying charge of approximately \$0.3 million on the North Dakota share of Big Stone II generation costs based on OTP’s average 2009 AFUDC rate of 7.65%. Because OTP would not earn a return on these deferred costs over the 36-month recovery period, the recoverable amount of \$4.3 million was discounted to its then present value of \$3.9 million using OTP’s incremental borrowing rate, in accordance with ASC 980 accounting requirements. The North Dakota portion of Big

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Stone II generation costs was recovered over a 36-month period which began on August 1, 2010.

The North Dakota jurisdictional share of Big Stone II costs incurred by OTP related to transmission was \$1.1 million. Approximately \$0.3 million of the total North Dakota jurisdictional share of Big Stone II transmission costs were transferred to the Big Stone South - Brookings MVP during the first quarter of 2013. On July 30, 2013 the NDPSC approved OTP's request to continue the Big Stone II cost recovery rates for an additional eight months through March 31, 2014 to recover the remaining North Dakota share of Big Stone II transmission-related costs plus accrued AFUDC totaling \$1.0 million. As of April 1, 2014 North Dakota customer's bills no longer include a charge for the North Dakota share of Big Stone II costs.

#### 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 2012 annual update to its South Dakota TCR on April 23, 2013 with an effective date of May 1, 2013. The SDPUC approved OTP's 2013 annual update on February 18, 2014 with an effective date of March 1, 2014. 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.

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 in their order dated October 15, 2015 with an effective date of November 1, 2015.

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:

<u>Rate Rider (in thousands)</u>	2015	2014
Minnesota		
Conservation Improvement Program Costs and Incentives <sup>1</sup>	\$10,724	\$ 7,757
Transmission Cost Recovery	5,202	6,275
Environmental Cost Recovery	10,238	6,891
North Dakota		
Renewable Resource Adjustment	8,409	7,484
Transmission Cost Recovery	6,609	5,794
Environmental Cost Recovery	9,502	5,872
Big Stone II Project Costs	--	361
South Dakota		
Transmission Cost Recovery	1,290	1,207
Environmental Cost Recovery	1,967	234
Conservation Improvement Program Costs and Incentives	583	435

<sup>1</sup>Includes MNCIP costs recovered in base rates.

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## 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 return on equity (ROE) component of the transmission rates that MISO transmission owners, including OTP, may collect under the MISO Tariff. The complainants are seeking to reduce the current 12.38% ROE used in MISO's transmission rates to a proposed 9.15%. A group of MISO transmission owners have filed responses to the complaint, defending the current ROE and seeking dismissal of the complaint. 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, subject to the outcome of settlement discussion. Settlement discussions did not resolve the dispute and the FERC set the proceeding to a Track II Hearing which occurred in August 2015. An initial decision by the presiding administrative law judge was issued on December 22, 2015 finding that the MISO transmission owners' ROE should be 10.32%. This order is currently pending exceptions at the FERC. 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 resolution of the ROE complaint proceeding.

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 the current 12.38% to a proposed 8.67%. A group of MISO transmission owners have filed responses to the complaint, defending the current ROE and seeking dismissal of the complaint. The FERC issued an order on June 18, 2015 setting the complaint for hearing to begin on February 16, 2016. The initial decision by the presiding administrative law judge is scheduled to be issued in the summer of 2016. A FERC decision is not expected until 2017.

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

### 3. Regulatory Assets and Liabilities

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:

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<i>(in thousands)</i>	December 31, 2015 Total	Remaining Recovery/ Refund Period
<b>Other Regulatory Assets:</b>		
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits <sup>1</sup>	\$106,732	see below
Deferred Marked-to-Market Losses <sup>1</sup>	14,593	60 months
Conservation Improvement Program Costs and Incentives <sup>2</sup>	8,677	18 months
Accumulated ARO Accretion/Depreciation Adjustment <sup>1</sup>	5,672	asset lives
Deferred Income Taxes <sup>1</sup>	1,455	asset lives
North Dakota Renewable Resource Rider Accrued Revenues <sup>2</sup>	1,266	15 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up <sup>2</sup>	1,053	24 months
Minnesota Transmission Cost Recovery Rider Accrued Revenues <sup>2</sup>	576	12 months
Minnesota Deferred Rate Case Expenses Subject to Recovery <sup>1</sup>	291	12 months
Minnesota Renewable Resource Rider Accrued Revenues <sup>2</sup>	68	see below
South Dakota Transmission Cost Recovery Rider Revenues <sup>2</sup>	33	12 months
<b>Total Other Regulatory Assets</b>	<b>\$140,416</b>	
<b>Other Regulatory Liabilities:</b>		
Revenue for Rate Case Expenses Subject to Refund – Minnesota	1,279	see below
Deferred Income Taxes	1,109	asset lives
Minnesota Environmental Cost Recovery Rider Accrued Refund	777	12 months
North Dakota Environmental Cost Recovery Rider Accrued Refund	321	12 months
South Dakota Environmental Cost Recovery Rider Accrued Refund	185	12 months
North Dakota Transmission Cost Recovery Rider Accrued Refund	132	12 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	100	216 months
North Dakota Renewable Resource Rider Accrued Refund	68	12 months
<b>Total Other Regulatory Liabilities</b>	<b>\$ 3,971</b>	
<b>Net Other Regulatory Asset Position</b>	<b>\$ 136,445</b>	

<sup>1</sup>Costs subject to recovery without a rate of return.

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

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<i>(in thousands)</i>	December 31, 2014 Total	Remaining Recovery/ Refund Period
<b>Other Regulatory Assets:</b>		
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits <sup>1</sup>	\$108,990	see below
Deferred Marked-to-Market Losses <sup>1</sup>	13,888	72 months
Conservation Improvement Program Costs and Incentives <sup>2</sup>	8,343	18 months
Accumulated ARO Accretion/Depreciation Adjustment <sup>1</sup>	5,190	asset lives
Minnesota Transmission Rider Accrued Revenues <sup>2</sup>	3,398	24 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up <sup>2</sup>	3,392	24 months
Deferred Income Taxes <sup>1</sup>	2,086	asset lives
North Dakota Transmission Rider Accrued Revenues <sup>2</sup>	859	12 months
North Dakota Environmental Cost Recovery Rider Accrued Revenues <sup>2</sup>	706	12 months
Minnesota Environmental Cost Recovery Rider Accrued Revenues <sup>2</sup>	186	12 months
Minnesota Renewable Resource Rider Accrued Revenues <sup>2</sup>	68	see below
South Dakota Environmental Cost Recovery Rider Accrued Revenues <sup>2</sup>	38	12 months
<b>Total Other Regulatory Assets</b>	<b>\$ 147,144</b>	
<b>Other Regulatory Liabilities:</b>		
Deferred Income Taxes	1,550	asset lives
North Dakota Renewable Resource Rider Accrued Refund	1,018	15 months
Revenue for Rate Case Expenses Subject to Refund – Minnesota	784	see below
Deferred Marked-to-Market Gains	257	67 months
Big Stone II Over Recovered Project Costs – North Dakota	147	12 months
Deferred Gain on Sale of Utility Property – Minnesota Portion	106	228 months
South Dakota Transmission Rider Accrued Refund	48	12 months
South Dakota – Nonasset-Based Margin Sharing Excess	24	12 months
<b>Total Other Regulatory Liabilities</b>	<b>\$ 3,934</b>	
<b>Net Other Regulatory Asset Position</b>	<b>\$ 143,210</b>	

<sup>1</sup>Costs subject to recovery without a rate of return.

<sup>2</sup>Amount 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, 2015 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.

The regulatory assets and liabilities related to Deferred Income Taxes result from changes in statutory tax rates accounted for in

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accordance with ASC Topic 740, *Income Taxes*.

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, 2015.

MISO Schedule 26/26A Transmission Cost Recovery Rider True-up relates to the over/under collection of revenue based on comparison of the expected versus actual construction on eligible projects in the period. The true-up also includes 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.

Minnesota Transmission Cost Recovery Rider Accrued Revenues relate to revenues earned on qualifying transmission system facilities that have not been billed to Minnesota customers as of December 31, 2015.

Minnesota Deferred Rate Case Expenses Subject to Recovery relate to costs incurred in conjunction with OTP's 2016 rate case in Minnesota that will be subject to recovery after new rates go into effect subsequent to the completion of the rate case.

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 in OTP's next general rate case.

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, 2015.

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.

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, 2015.

The North Dakota Environmental Cost Recovery Rider Accrued Refund relates to amounts collected on the North Dakota share of OTP's investments in the Big Stone Plant AQCS and Hoot Lake Plant MATS projects that are refundable to North Dakota customers as of December 31, 2015.

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, 2015.

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, 2015.

The North Dakota Renewable Resource Rider Accrued Refund relates to amounts collected for qualifying renewable resource costs incurred to serve North Dakota customers that are refundable to North Dakota customers as of December 31, 2015.

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 the balance sheet and included in the statement of income as an expense or income item in the period in which the application of guidance under ASC 980 ceases.

#### **4. Forward Contracts Classified as Derivatives**

##### Electricity Contracts

All of OTP's wholesale purchases and sales of energy under forward contracts that are not designated as normal are accounted for as

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derivatives subject to mark-to-market accounting. OTP's objective in entering into forward contracts for the purchase and sale of energy is to meet the energy requirements of its retail customers and to optimize the use of its generating and transmission facilities. OTP's intent in entering into these contracts is to settle them through the physical delivery of energy when physically possible and economically feasible. Prior to December 2014, OTP also entered into certain contracts for trading purposes with the intent to profit from fluctuations in market prices through the timing of purchases and sales. Effective December 31, 2014 OTP discontinued its trading activities not directly associated with serving retail customers.

OTP's forward contracts outstanding as of September 30, 2015 and December 31, 2014 for the purchase of electricity were scheduled for delivery at the OTP node. Prices used to value these forward purchases were based on a basis spread between the OTP node and more liquid trading hub prices. These basis spreads were based on historical spreads. The fair value measurements of these forward energy contracts fell into Level 3 of the fair value hierarchy set forth in ASC 820.

Electric operating revenues include wholesale electric sales, the acquisition and settlement of financial transmission rights and transmission congestion rights and daily settlements of virtual transactions in the MISO market and, prior to December 31, 2014, included net unrealized derivative gains on forward energy contracts, the acquisition and settlement of congestion revenue rights options in the Electric Reliability Council of Texas (ERCOT) markets and daily settlements of virtual transactions in the ERCOT, California Independent Transmission System Operator markets and Southwest Power Pool markets broken down as follows for the years ended December 31:

<i>(in thousands)</i>	2015	2014
Wholesale Sales - Company-Owned Generation	\$ 2,499	\$ 11,160
Revenue from Settled Contracts at Market Prices	20,545	131,952
Market Cost of Settled Contracts	(20,359)	(130,908)
Net Margins on Settled Contracts at Market	186	1,044
Marked-to-Market Gains on Settled Contracts	--	263
Marked-to-Market Losses on Settled Contracts	--	(276)
Net Marked-to-Market Losses on Settled Contracts	--	(13)
Wholesale Electric Revenue	\$ 2,685	\$ 12,191

OTP has established guidelines and limits to manage credit risk associated with wholesale power and capacity purchases and sales. Specific limits are determined by a counterparty's financial strength. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). OTP had no exposure at December 31, 2015 to counterparties with investment grade or below investment grade credit ratings with respect to any of its forward energy contracts.

Individual counterparty exposures for certain contracts can be offset according to legally enforceable netting arrangements. However, OTP does not net offsetting payables and receivables or derivative assets and liabilities under legally enforceable netting arrangements on the face of its balance sheet. The following table shows forward contract positions subject to legally enforceable netting arrangements as of December 31:

<i>(in thousands)</i>	2015	2014
Derivatives in Gain Positions Subject to Legally Enforceable Netting Arrangements	\$ --	\$ 257
Open Contract Loss Positions Subject to Legally Enforceable Netting Arrangements	(16,070)	(14,230)
Net Balance Subject to Legally Enforceable Netting Arrangements	\$ (16,070)	\$ (13,973)

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>	2015	2014
Loss Contracts Covered by Deposited Funds or Letters of Credit	\$ 199	\$ 45
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade <sup>1</sup>	15,871	13,888
Loss Contracts with No Ratings Triggers or Deposit Requirements	--	297
Total Forward Contracts In Excess of Current Market Values	\$ 16,070	\$ 14,230

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*1 Certain 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.*

Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade	\$ 15,871	\$ 13,888
Offsetting Gains with Counterparties under Master Netting Agreements	--	(257)
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	\$ 15,871	\$ 13,631

## 5. Common Shareholder's Equity

Otter Tail Corporation completed its holding company reorganization in July 2009. In conjunction with the reorganization, OTP issued 100 shares of common stock with a par value of \$5 per share, with the sole holder of those shares being Otter Tail Corporation. In 2015, Otter Tail Corporation made cash equity contributions to OTP totaling \$43,728,000. In 2014, Otter Tail Corporation made cash equity contributions totaling \$44,000,000.

## 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, 2015 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 46.9% and 57.3%. OTP's equity to total capitalization ratio including short-term debt was 51.6% as of December 31, 2015. Total capitalization for OTP cannot currently exceed \$1,056,300,000.

## 7. Commitments and Contingencies

### Construction and Other Purchase Commitments

At December 31, 2015 OTP had commitments under contracts, including its share of construction program commitments extending into 2019, of approximately \$89.6 million.

### Electric Utility Capacity and Energy Requirements and Coal and Delivery Contracts

OTP has commitments for the purchase of capacity and energy requirements under agreements extending into 2040. OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. OTP's current coal purchase agreements, under which OTP is committed to the minimum purchase amounts or to make payments in lieu thereof, expire in 2016, 2017 and 2040. 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 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 \$1,899,000 for 2015 and \$2,680,000 for 2014.

The amounts of OTP's commitments under capacity and energy agreements, coal and coal delivery contracts and operating leases as of

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December 31, 2015, are as follows:

<i>(in thousands)</i>	Construction Program and Other Commitments	Capacity and Energy Requirements	Coal and Freight Purchase Commitments	Operating Leases
2016	\$ 56,683	\$ 22,821	\$ 47,821	\$ 2,485
2017	27,325	22,146	31,797	1,913
2018	5,586	22,753	22,733	1,220
2019	46	24,555	21,965	997
2020	--	25,401	24,482	1,009
Beyond 2020	--	193,536	574,808	9,824
Total	\$ 89,640	\$ 311,212	\$ 723,606	\$ 17,448

### Contingencies

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 impacting OTP's financial statements are those related to environmental remediation and litigation matters. Should all of these known items result in liabilities being incurred, the loss could be as high as \$1.4 million.

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

In 2014, the EPA published proposed standards of performance for CO<sub>2</sub> emissions from new fossil fuel-fired power plants, proposed CO<sub>2</sub> emission guidelines for existing fossil fuel-fired power plants and proposed CO<sub>2</sub> standards of performance for CO<sub>2</sub> emissions from reconstructed and modified fossil fuel-fired power plants, essentially requiring that such plants install updated control technology when constructing, modifying or reconstructing to reduce their emissions. The EPA published final rules for each of these proposals on October 23, 2015. On February 9, 2016 the U.S. Supreme Court granted a stay of the CO<sub>2</sub> emission guidelines for existing fossil fuel-fired power plants, pending disposition of petitions for review in the D.C. Circuit and disposition of a petition for a writ of certiorari seeking review by the U.S. Supreme Court, if such a writ is sought. The rules are subject to pending judicial challenges, and consequently, uncertainty regarding the status of the rules will likely continue for some time. OTP is currently assessing the potential impact of these rules on existing affected sources of CO<sub>2</sub> emissions at OTP.

### Other

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, 2015 will not be material.

## **8. Short-Term and Long-Term Borrowings**

### **Short-Term Debt**

The following table presents the status of OTP's lines of credit as of December 31, 2015 and December 31, 2014:

<i>(in thousands)</i>	Line Limit	In Use on December 31, 2015	Restricted due to Outstanding Letters of Credit	Available on December 31, 2015	Available on December 31, 2014
OTP Credit Agreement	\$ 170,000	\$ 21,006	\$ 300	\$ 148,694	\$ 169,440

Under the OTP Credit Agreement (as defined below), the maximum amount of debt outstanding in 2015 was \$22,864,000 on

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December 15, 2015 and the average daily balance of debt outstanding during 2015 was \$7,876,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2015 was 1.5% compared with 1.4% in 2014. The weighted average interest rate on OTP's short-term debt outstanding on December 31, 2015 was 1.5%.

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 29, 2015 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2019 to October 29, 2020. 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 has 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 term loan 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 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

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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, 2015 for each of the next five years are:

<i>(in thousands)</i>	2016	2017	2018	2019	2020
Aggregate Amounts of Debt Maturities	\$ --	\$ 33,000	\$ --	\$ --	\$ --

## Financial Covenants

OTP was in compliance with the financial covenants in their debt agreements as of December 31, 2015.

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 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

### Pension Plan

The noncontributory funded pension plan covers substantially all OTP nonunion employees hired prior to January 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

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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>	2015	2014
Service Cost—Benefit Earned During the Period	\$ 5,908	\$ 4,554
Interest Cost on Projected Benefit Obligation	13,010	12,796
Expected Return on Assets	(17,923)	(16,341)
Amortization of Prior-Service Cost from Regulatory Asset	188	257
Amortization of Net Actuarial Loss from Regulatory Asset	6,676	3,400
Net Periodic Pension Cost	\$ 7,859	\$ 4,666

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

	2015	2014
Discount Rate	4.35%	5.30%
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:

<i>(in thousands)</i>	2015	2014
Regulatory Assets:		
Unrecognized Prior Service Cost	\$ 329	\$ 518
Unrecognized Actuarial Loss	101,974	97,722
Total Regulatory Assets	\$ 102,303	\$ 98,240
Noncurrent Liability	\$ 67,373	\$ 65,451

Funded status as of December 31:

<i>(in thousands)</i>	2015	2014
Accumulated Benefit Obligation	\$(261,677)	\$(267,330)
Projected Benefit Obligation	\$(295,171)	\$(304,170)
Fair Value of Plan Assets	227,798	238,719
Funded Status	\$ (67,373)	\$ (65,451)

The following tables provide a reconciliation of the changes in the OTP portion of the fair value of plan assets and the plan's benefit obligations over the two-year period ended December 31, 2015:

<i>(in thousands)</i>	2015	2014
Reconciliation of OTP's Portion of the Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	\$ 238,719	\$ 208,063
Actual Return on Plan Assets	(9,240)	21,449
Discretionary Company Contributions	10,000	20,000
Benefit Payments	(11,681)	(10,793)
Fair Value of Plan Assets at December 31	\$ 227,798	\$ 238,719
Estimated Asset Return	(3.7)%	9.6%

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Reconciliation of OTP's Portion of the Projected Benefit Obligation:

Projected Benefit Obligation at January 1	\$ 304,170	\$ 247,434
Service Cost	5,908	4,554
Interest Cost	13,010	12,796
Benefit Payments	(11,681)	(10,793)
Actuarial (Gain) Loss	(16,236)	50,179
Projected Benefit Obligation at December 31	\$ 295,171	\$ 304,170

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

	2015	2014
Discount Rate	4.76%	4.35%
Rate of Increase in Future Compensation Level	3.13%	3.13%

The assumed rate of return on pension fund assets used for the determination of 2016 net periodic pension cost is 7.75%. 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 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:	2015	2014
Net Periodic Pension Cost	January 1, 2015	January 1, 2014
End of Year Benefit Obligations	January 1, 2015 projected to December 31, 2015	January 1, 2014 projected to December 31, 2014
Market Value of Assets	December 31, 2015	December 31, 2014

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 2016 are:

<i>(in thousands)</i>	2016
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 189
Amortization of Unrecognized Actuarial Loss	4,908
Total Estimated Amortization	\$ 5,097

Cash flows—OTP had no minimum funding requirement as of December 31, 2015, but OTP made a discretionary plan contribution of \$10,000,000 in January 2016.

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

<i>(in thousands)</i>	2016	2017	2018	2019	2020	Years 2021-2025
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\$12,453      \$13,057      \$13,822      \$14,509      \$15,358      \$88,160

The following objectives guide the investment strategy of the OTP's pension plan (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:

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, 2015 and 2014, by asset category are as follows:

Asset Allocation	2015	2014
Large Capitalization Equity Securities	21.2%	21.0%
International Equity Securities	21.6%	18.9%
Small and Mid-Capitalization Equity Securities	8.1%	7.9%
SEI Dynamic Asset Allocation Fund	5.6%	5.5%
Equity Securities	56.5%	53.3%
Fixed-Income Securities and Cash	35.8%	42.7%
Other - SEI Special Situation Collective Investment Trust	4.1%	4.0%
Other - SEI Energy Debt Collective Fund	3.6%	--
	100.0%	100.0%

In December 2015, OTP adopted the accounting standards updates in ASU 2015-07, which eliminated the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the NAV practical expedient.

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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 NAV practical expedient to fair valuation as of December 31:

<i>(in thousands)</i>	2015	2014
Assets in Level 1 of the Fair Value Hierarchy	\$ 210,284	\$ 229,154
SEI Special Situation Collective Investment Trust Fund at NAV	9,381	9,565
SEI Energy Debt Fund at NAV	8,133	--
Total Assets	\$ 227,798	\$ 238,719

#### 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:

<i>(in thousands)</i>	2015	2014
Large Capitalization Equity Securities Mutual Fund	\$ 48,275	\$ 50,171
International Equity Securities Mutual Funds	49,241	45,176
Small and Mid-Capitalization Equity Securities Mutual Fund	18,353	18,729
SEI Dynamic Asset Allocation Mutual Fund	12,679	13,218
Fixed Income Securities Mutual Funds	81,734	101,855
Cash Management – Money Market Fund	2	5
Total Assets	\$ 210,284	\$ 229,154

The investments held by the SEI Special Situation Collective Investment Trust on December 31, 2015 and 2014 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 Fund on December 31, 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:

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<i>(in thousands)</i>	2015	2014
Service Cost–Benefit Earned During the Period	\$ 76	\$ 41
Interest Cost on Projected Benefit Obligation	728	819
Amortization of Prior Service Cost:		
From Regulatory Asset	16	22
From Other Comprehensive Income <sup>1</sup>	15	20
Amortization of Net Actuarial Loss:		
From Regulatory Asset	334	142
From Other Comprehensive Income <sup>1</sup>	310	132
<b>Net Periodic Pension Cost</b>	<b>\$ 1,479</b>	<b>\$ 1,176</b>

<sup>1</sup>Amortization 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:

	2015	2014
Discount Rate	4.35%	5.30%
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>	2015	2014
Regulatory Assets:		
Unrecognized Prior Service Cost	\$ 75	\$ 91
Unrecognized Actuarial Loss	2,936	3,238
<b>Total Regulatory Assets</b>	<b>\$ 3,011</b>	<b>\$ 3,329</b>
Projected Benefit Obligation Liability – Net Amount Recognized	\$(17,107)	\$(17,360)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	\$ 69	\$ 84
Unrecognized Actuarial Loss	2,725	3,005
<b>Total Accumulated Other Comprehensive Loss</b>	<b>\$ 2,794</b>	<b>\$ 3,089</b>

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, 2015 and a statement of the funded status as of December 31 of both years:

<i>(in thousands)</i>	2015	2014
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	1,119	1,113
Benefit Payments	(1,119)	(1,113)
<b>Fair Value of Plan Assets at December 31</b>	<b>\$ --</b>	<b>\$ --</b>
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 17,360	\$ 16,093
Service Cost	76	41
Interest Cost	728	819
Benefit Payments	(1,119)	(1,113)
Liability Transfer from OTP to Otter Tail Corporation	--	(1,196)
Actuarial Loss	62	2,716
<b>Projected Benefit Obligation at December 31</b>	<b>\$ 17,107</b>	<b>\$ 17,360</b>

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

	2015	2014
Discount Rate	4.76%	4.35%
Rate of Increase in Future Compensation Level	3.25%	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 2016 are:

<i>(in thousands)</i>	2016
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 16
Amortization of Unrecognized Actuarial Loss	293
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	15
Amortization of Unrecognized Actuarial Loss	272
<u>Total Estimated Amortization</u>	<u>\$ 596</u>

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>	2016	2017	2018	2019	2020	Years 2021-2025
	\$1,244	\$1,214	\$1,261	\$1,336	\$1,321	\$6,035

#### **Other Postretirement Benefits**

OTP provides a portion of health insurance and life insurance benefits for retired OTP employees. Substantially all of OTP's electric 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>	2015	2014
Service Cost—Benefit Earned During the Period	\$ 1,264	\$ 1,030
Interest Cost on Projected Benefit Obligation	2,045	2,147
Amortization of Prior Service Cost from Regulatory Asset	205	205
Amortization of Net Actuarial Loss from Regulatory Asset	--	--
<u>Net Periodic Postretirement Benefit Cost</u>	<u>\$ 3,514</u>	<u>\$ 3,382</u>
Effect of Medicare Part D Subsidy	\$ (1,450)	\$ (925)

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

	2015	2014
Discount Rate	4.20%	5.10%

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

<i>(in thousands)</i>	2015	2014
Regulatory Asset:		
Unrecognized Prior Service Cost	\$ 129	\$ 335
Unrecognized Net Actuarial Loss	1,289	7,086
<u>Net Regulatory Asset</u>	<u>\$ 1,418</u>	<u>\$ 7,421</u>
<u>Projected Benefit Obligation Liability – Net Amount Recognized</u>	<u>\$ (47,512)</u>	<u>\$ (52,337)</u>

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations

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over the two-year period ended December 31, 2015:

<i>(in thousands)</i>	2015	2014
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	2,336	2,316
Benefit Payments (Net of Medicare Part D Subsidy)	(5,286)	(5,005)
Participant Premium Payments	2,950	2,689
Fair Value of Plan Assets at December 31	\$ --	\$ --
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 52,337	\$ 44,046
Service Cost (Net of Medicare Part D Subsidy)	1,264	1,030
Interest Cost (Net of Medicare Part D Subsidy)	2,045	2,147
Benefit Payments (Net of Medicare Part D Subsidy)	(5,286)	(5,005)
Participant Premium Payments	2,950	2,689
Actuarial (Gain) Loss	(5,798)	7,430
Projected Benefit Obligation at December 31	\$ 47,512	\$ 52,337

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

	2015	2014
Discount Rate	4.57%	4.20%

Assumed healthcare cost-trend rates as of December 31:

	2015	2014
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	6.16%	6.32%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	6.43%	6.63%
Rate to Which the Cost-Trend Rate is Assumed to Decline	4.50%	5.00%
Year the Rate Reaches the Ultimate Trend Rate	2038	2025

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 2015 would have the following effects:

<i>(in thousands)</i>	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	\$ 6,049	\$ (5,007)
Effect on Total of Service and Interest Cost	\$ 638	\$ (496)
Effect on Expense	\$ 1,322	\$ (496)

Measurement Dates:	2015	2014
Net Periodic Postretirement Benefit Cost	January 1, 2015	January 1, 2014
End of Year Benefit Obligations	January 1, 2015 projected to December 31, 2015	January 1, 2014 projected to December 31, 2014

The estimated net amounts of unrecognized prior service cost to be amortized from regulatory assets into the net periodic postretirement benefit cost in 2016 are:

<i>(in thousands)</i>	2016
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 134
Amortization of Unrecognized Actuarial Loss	--
Total Estimated Amortization	\$ 134

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Cash flows—OTP expects to contribute \$2.6 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2016. OTP expects to receive a Medicare Part D subsidy from the Federal government of approximately \$454,000 in 2016. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

<i>(in thousands)</i>	2016	2017	2018	2019	2020	Years 2021-2025
	\$2,619	\$2,781	\$2,913	\$3,053	\$3,126	\$16,352

#### **401K Plan**

OTP has a 401K plan for the benefit of all its employees. Contributions made to this plan by OTP totaled \$1,985,000 for 2015 and \$1,782,000 for 2014.

#### **Employee Stock Ownership Plan**

OTP has a stock ownership plan for the benefit of all its employees. Contributions made by OTP were \$674,000 for 2015 and \$696,000 for 2014.

### **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, 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, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-Term Investments	\$ 28	\$ 28	\$ 178	\$ 178
Short-Term Debt	(21,006)	(21,006)	--	--
Long-Term Debt including Current Maturities	(445,000)	(506,052)	(445,000)	(540,084)

### **11. Property, Plant and Equipment**

<i>(in thousands)</i>	December 31, 2015	December 31, 2014	Service Life Range <i>(years)</i>	
			Low	High
<b>Electric Plant</b>				
Production	\$ 879,121	\$ 690,024	34	62
Transmission	391,941	323,496	40	70
Distribution	451,820	438,489	15	55
General	97,881	93,103	5	70
Electric Plant in Service	1,820,763	1,545,112		
Construction Work in Progress	64,117	240,170		
<b>Total Plant</b>	1,884,880	1,785,282		
Less Accumulated Depreciation and Amortization	666,949	659,194		
<b>Net Plant</b>	\$ 1,217,931	\$ 1,126,088		

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## 12. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2015 and 2014) to net income before total income tax expense for the following reasons:

<i>(in thousands)</i>	2015	2014
Tax Computed at Federal Statutory Rate	\$ 22,553	\$ 19,150
Increases (Decreases) in Tax from:		
State Income Taxes Net of Federal Income Tax Benefit	3,828	1,421
Federal Production Tax Credit	(6,962)	(7,517)
Differences Reversing in Excess of Federal Rates	(1,143)	(106)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(850)	(849)
Investment Tax Credit Amortization	(571)	(597)
Dividend Received/Paid Deduction	(560)	(622)
Allowance for Funds Used During Construction - Equity	(426)	(505)
Tax Depreciation - Treasury Grant for Wind Farms	--	(152)
Permanent and Other Differences	198	806
<b>Total Income Tax Expense</b>	<b>\$ 16,067</b>	<b>\$ 11,029</b>
Overall Effective Federal and State Income Tax Rate	24.9%	20.2%
Income Tax Expense Includes the Following:		
Current Federal Income Taxes	\$ 231	\$ 125
Deferred Federal Income Taxes	18,331	16,375
Deferred State Income Taxes	5,888	3,492
Federal Production Tax Credit	(6,962)	(7,517)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(850)	(849)
Investment Tax Credit Amortization	(571)	(597)
<b>Total</b>	<b>\$ 16,067</b>	<b>\$ 11,029</b>

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

<i>(in thousands)</i>	2015	2014
Deferred Tax Assets		
North Dakota Wind Tax Credits	\$ 41,326	\$ 41,783
Net Operating Loss Carryforward	28,423	4,539
Benefit Liabilities	26,129	25,728
Federal Production Tax Credits	25,938	18,763
Differences Related to Property	8,453	8,676
Other	5,822	4,747
Vacation Accrual	1,661	1,667
Investment Tax Credits	1,109	1,549
<b>Total Deferred Tax Assets</b>	<b>\$ 138,861</b>	<b>\$ 107,452</b>
Deferred Tax Liabilities		
Differences Related to Property	\$(319,556)	\$(270,101)
Renewable Resource Rider Accrued Revenue	(732)	139
Excess Tax over Book Pension	(13,775)	(12,928)
Other	(6,863)	(7,787)
North Dakota Wind Tax Credits	(11,543)	(11,543)
Impact of State Net Operating Losses on Federal Taxes	(1,481)	(1,595)
Regulatory Asset	(1,455)	(2,087)
<b>Total Deferred Tax Liabilities</b>	<b>\$(355,405)</b>	<b>\$(305,902)</b>
<b>Deferred Income Taxes</b>	<b>\$(216,544)</b>	<b>\$(198,450)</b>

Federal PTCs are earned as wind energy is generated based on a per kwh rate prescribed in applicable federal statutes. OTP's kwh

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generation from its wind turbines eligible for PTCs decreased 7.4% primarily due to lower average wind speed in 2015 compared with 2014. 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, 2015:

<i>(in thousands)</i>	Amount	2016	2017	2027-35
<b>United States</b>				
Federal Net Operating Losses	\$ 24,208	\$ --	\$ --	\$ 24,208
Federal Tax Credits	25,938	--	--	25,938
State Net Operating Losses	4,215	--	--	4,215
State Tax Credits	32,962	2,339	389	30,234

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 \$2.7 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>	2015	2014
Balance on January 1	\$ 222	\$ 4,239
Increases Related to Tax Positions for Prior Years	236	120
Decreases Related to Tax Positions for Prior Years	--	(4,142)
Increases Related to Tax Positions for Current Year	10	5
Balance on December 31	\$ 468	\$ 222

The balance of unrecognized tax benefits as of December 31, 2015 would reduce the OTP's effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2015 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, 2015.

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, 2015, with limited exceptions, Otter Tail Corporation is no longer subject to examinations by taxing authorities for tax years prior to 2012 for federal and North Dakota state income taxes and for tax years prior to 2013 for Minnesota 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.

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 will have no impact on current year operating expenses but will result 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.

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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, 2015 and 2014 are presented in the following table:

<i>(in thousands)</i>	2015	2014
<u>Asset Retirement Obligations</u>		
Beginning Balance	\$ 7,721	\$ 5,661
New Obligations Recognized	451	--
Adjustments Due to Revisions in Cash Flow Estimates	(424)	1,582
Accrued Accretion	336	478
Settlements	--	--
Ending Balance	\$ 8,084	\$ 7,721
<u>Asset Retirement Costs Capitalized</u>		
Beginning Balance	\$ 3,059	\$ 1,477
New Obligations Recognized	451	--
Adjustments Due to Revisions in Cash Flow Estimates	(424)	1,582
Settlements	--	--
Ending Balance	\$ 3,086	\$ 3,059
<u>Accumulated Depreciation - Asset Retirement Costs Capitalized</u>		
Beginning Balance	\$ 527	\$ 462
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Depreciation Expense	146	65
Settlements	--	--
Ending Balance	\$ 673	\$ 527
<u>Settlements</u>		
Original Capitalized Asset Retirement Cost - Retired	\$ --	\$ --
Accumulated Depreciation	--	--
Asset Retirement Obligation	\$ --	\$ --
Settlement Cost	--	--
Gain on Settlement – Deferred Under Regulatory Accounting	\$ --	\$ --

#### 14. Quantitative and Qualitative disclosures about Market Risk

At December 31, 2015 OTP had exposure to market risk associated with interest rates related to \$21.0 million in short-term debt outstanding subject to variable interest rates indexed to LIBOR plus 1.25% under the OTP Credit Agreement.

All of OTP's long-term debt outstanding on December 31, 2015 has fixed interest rates. OTP manages its interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt.

OTP has not used interest rate swaps to manage net exposure to interest rate changes related to our portfolio of borrowings. OTP maintains a ratio of fixed-rate debt to total debt within a certain range. It is OTP's policy to enter into interest rate transactions and other financial instruments only to the extent considered necessary to meet our stated objectives. OTP does not enter into interest rate transactions for speculative or trading purposes.

OTP has in place an energy risk management policy with a goal to manage, through the use of defined risk management practices, price risk and credit risk associated with wholesale power sales. OTP has established guidelines and limits to manage credit risk associated with wholesale power and capacity sales. Specific limits are determined by a counterparty's financial strength. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). OTP had no exposure at December 31, 2015 to counterparties with investment grade or below investment grade credit ratings with respect to any of its forward energy contracts.

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				( 1,160,288)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				91,421
3	Preceding Quarter/Year to Date Changes in Fair Value				( 784,355)
4	Total (lines 2 and 3)				( 692,934)
5	Balance of Account 219 at End of Preceding Quarter/Year				( 1,853,222)
6	Balance of Account 219 at Beginning of Current Year				( 1,853,222)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				195,012
8	Current Quarter/Year to Date Changes in Fair Value				( 17,900)
9	Total (lines 7 and 8)				177,112
10	Balance of Account 219 at End of Current Quarter/Year				( 1,676,110)



**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)	1,506,783,055	1,506,783,055
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	312,303,175	312,303,175
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,819,086,230	1,819,086,230
9	Leased to Others		
10	Held for Future Use	29,656	29,656
11	Construction Work in Progress	64,117,181	64,117,181
12	Acquisition Adjustments	1,647,129	1,647,129
13	Total Utility Plant (8 thru 12)	1,884,880,196	1,884,880,196
14	Accum Prov for Depr, Amort, & Depl	666,949,303	666,949,303
15	Net Utility Plant (13 less 14)	1,217,930,893	1,217,930,893
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	660,113,917	660,113,917
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	5,188,258	5,188,258
22	Total In Service (18 thru 21)	665,302,175	665,302,175
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)	666,949,303	666,949,303

Name of Respondent  
Otter Tail Power Company

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

Date of Report  
(Mo, Da, Yr)  
12/31/2015

Year/Period of Report  
End of 2015/Q4

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

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

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) 12/31/2015	2015/Q4
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, 2014	1,543,435,386
January 31, 2015	1,543,418,567
February 28, 2015	1,552,226,956
March 31, 2015	1,558,782,024
April 30, 2015	1,578,444,842
May 31, 2015	1,579,434,727
June 30, 2015	1,581,491,902
July 31, 2015	1,582,581,813
August 31, 2015	1,586,913,688
September 30, 2015	1,588,610,369
October 31, 2015	1,605,729,336
November 30, 2015	1,603,279,499
December 31, 2015	1,819,086,230
13-month average for rate-making	1,594,110,411

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

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

	Account 107 Balance	CWIP not in Rates	CWIP in Rate Base
December 31, 2014	240,169,972	180,625,670	59,544,302
January 31, 2015	249,628,911	188,559,520	61,069,391
February 28, 2015	250,606,664	192,104,120	58,502,544
March 31, 2015	257,462,025	202,697,276	54,764,749
April 30, 2015	232,449,156	216,318,437	16,130,719
May 31, 2015	244,766,650	227,542,341	17,224,309
June 30, 2015	251,931,540	233,884,203	18,047,337
July 31, 2015	259,320,781	239,817,449	19,503,332
August 31, 2015	258,623,827	238,261,302	20,362,525
September 30, 2015	265,659,517	242,625,254	23,034,263
October 31, 2015	257,322,557	230,288,947	27,033,610
November 30, 2015	268,285,382	238,362,594	29,922,788
December 31, 2015	64,117,181	26,405,843	37,711,338
13-month average for rate-making			34,065,477

**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)

12/31/2015

Year/Period of Report

End of 2015/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
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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) 12/31/2015	Year/Period of Report 2015/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	6,971,196	2,000,854
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	8,273,170	2,000,854
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,710,632	-51,400
9	(311) Structures and Improvements	61,217,979	63,405,719
10	(312) Boiler Plant Equipment	210,531,164	136,145,735
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	64,778,484	1,550,083
13	(315) Accessory Electric Equipment	24,055,623	12,909,819
14	(316) Misc. Power Plant Equipment	5,465,563	862,224
15	(317) Asset Retirement Costs for Steam Production	2,834,190	26,895
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	370,593,635	214,849,075
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	4,264,063	12,994
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)	7,324,285	12,994
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	31,809,693	182,859
41	(344) Generators	241,245,031	876,650
42	(345) Accessory Electric Equipment	20,524,063	87,430
43	(346) Misc. Power Plant Equipment	590,942	29,500
44	(347) Asset Retirement Costs for Other Production	224,652	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	309,215,618	1,176,439
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	687,133,538	216,038,508

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	7,667,137	3,424,521
49	(352) Structures and Improvements		
50	(353) Station Equipment	79,546,489	6,774,459
51	(354) Towers and Fixtures	44,899,477	38,910,439
52	(355) Poles and Fixtures	99,696,518	9,947,885
53	(356) Overhead Conductors and Devices	91,542,147	10,997,030
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)	323,429,229	70,054,334
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	1,094,865	66,835
61	(361) Structures and Improvements		
62	(362) Station Equipment	74,334,665	2,680,086
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	67,912,726	1,619,110
65	(365) Overhead Conductors and Devices	48,201,538	1,100,587
66	(366) Underground Conduit		770
67	(367) Underground Conductors and Devices	69,172,480	2,750,042
68	(368) Line Transformers	85,366,297	4,849,271
69	(369) Services	50,610,378	1,903,807
70	(370) Meters	32,443,323	1,284,430
71	(371) Installations on Customer Premises	4,348,944	282,471
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,982,665	259,850
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	438,467,881	16,797,259
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	30,389,957	97,904
88	(391) Office Furniture and Equipment	8,796,591	891,868
89	(392) Transportation Equipment	31,729,162	2,976,469
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	4,409,826	350,008
92	(395) Laboratory Equipment		
93	(396) Power Operated Equipment	605,062	
94	(397) Communication Equipment	8,679,074	317,670
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	86,131,568	4,633,919
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)	86,131,568	4,633,919
100	TOTAL (Accounts 101 and 106)	1,543,435,386	309,524,874
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)	1,543,435,386	309,524,874

**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
			8,972,050		4
			10,274,024		5
					6
					7
5,075			1,654,157		8
289,384			124,334,314		9
24,547,320			322,129,579		10
					11
856,306			65,472,261		12
369,621			36,595,821		13
89,759			6,238,028		14
			2,861,085		15
26,157,465			559,285,245		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
95,040			31,897,512		40
608,740			241,512,941		41
65,211			20,546,282		42
14,774			605,668		43
			224,652		44
783,765			309,608,292		45
26,941,230			876,230,816		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
		-82,690	11,008,968	48
				49
549,298		-303,581	85,468,069	50
		2,075,127	85,885,043	51
367,304		-2,058,769	107,218,330	52
307,230		-16,359	102,215,588	53
				54
			77,461	55
				56
				57
1,223,832		-386,272	391,873,459	58
				59
		82,690	1,244,390	60
				61
1,735,567		216,773	75,495,957	62
				63
103,077			69,428,759	64
147,768		-9,089	49,145,268	65
		-770		66
263,127		16,886	71,676,281	67
521,544		67,990	89,762,014	68
67,962		200	52,446,423	69
766,903			32,960,850	70
149,037		-200	4,482,178	71
				72
85,536			5,156,979	73
				74
3,840,521		374,480	451,799,099	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			1,521,896	86
60,349		-14,952	30,412,560	87
245,470		38,900	9,481,889	88
1,276,613			33,429,018	89
				90
190,325		-23,948	4,545,561	91
				92
			605,062	93
95,690		11,792	8,912,846	94
				95
1,868,447		11,792	88,908,832	96
				97
				98
1,868,447		11,792	88,908,832	99
33,874,030			1,819,086,230	100
				101
				102
				103
33,874,030			1,819,086,230	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) 12/31/2015	Year/Period of Report 2015/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, 2014	8,273,170
January 31, 2015	8,273,170
February 28, 2015	8,273,170
March 31, 2015	8,273,170
April 30, 2015	8,273,170
May 31, 2015	8,273,170
June 30, 2015	8,273,170
July 31, 2015	8,273,170
August 31, 2015	8,273,170
September 30, 2015	8,273,170
October 31, 2015	10,097,777
November 30, 2015	10,097,777
December 31, 2015	10,274,024
13-month average for rate-making	8,707,791

**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, 2014	687,133,538
January 31, 2015	686,656,510
February 28, 2015	686,656,312
March 31, 2015	685,990,695
April 30, 2015	664,650,440
May 31, 2015	664,447,114
June 30, 2015	664,898,396
July 31, 2015	664,935,691
August 31, 2015	665,748,365
September 30, 2015	665,762,700
October 31, 2015	675,741,141
November 30, 2015	672,575,032
December 31, 2015	876,280,816
13-month average for rate-making	689,340,519

**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, 2014	323,429,229
January 31, 2015	323,849,304
February 28, 2015	331,899,721
March 31, 2015	338,164,531
April 30, 2015	378,904,120
May 31, 2015	379,873,790

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) 12/31/2015	2015/Q4
FOOTNOTE DATA			

June 30, 2015	380,616,124
July 31, 2015	380,766,506
August 31, 2015	383,342,040
September 30, 2015	383,477,853
October 31, 2015	387,059,067
November 30, 2015	387,144,759
December 31, 2015	391,873,459
13-month average for rate-making	366,953,885

**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, 2014	438,467,881
January 31, 2015	438,588,111
February 28, 2015	439,638,846
March 31, 2015	440,525,045
April 30, 2015	440,789,296
May 31, 2015	440,954,985
June 30, 2015	441,798,732
July 31, 2015	442,514,099
August 31, 2015	443,464,382
September 30, 2015	445,221,464
October 31, 2015	445,698,956
November 30, 2015	446,545,468
December 31, 2015	451,799,099
13-month average for rate-making	442,769,720

**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, 2014	86,131,568
January 31, 2015	86,051,473
February 28, 2015	85,758,907
March 31, 2015	85,828,582
April 30, 2015	85,827,817
May 31, 2015	85,885,668
June 30, 2015	85,905,480
July 31, 2015	86,092,348
August 31, 2015	86,085,730
September 30, 2015	85,875,181
October 31, 2015	87,132,394
November 30, 2015	86,916,464
December 31, 2015	88,908,833
13-month average for rate-making	86,338,496

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					
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15					
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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				
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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) 12/31/2015	Year/Period of Report 2015/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, 2014	9,037	20,619	29,656
January 31, 2015	9,037	20,619	29,656
February 28, 2015	9,037	20,619	29,656
March 31, 2015	9,037	20,619	29,656
April 30, 2015	9,037	20,619	29,656
May 31, 2015	9,037	20,619	29,656
June 30, 2015	9,037	20,619	29,656
July 31, 2015	9,037	20,619	29,656
August 31, 2015	9,037	20,619	29,656
September 30, 2015	9,037	20,619	29,656
October 31, 2015	9,037	20,619	29,656
November 30, 2015	9,037	20,619	29,656
December 31, 2015	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, SD - Transmission line	14,210,370
2	Big Stone, SD - Ellendale, ND - Transmission line	8,335,015
3	Big Stone, SD - Big Stone South, SD - Transmission line	1,380,571
4	Big Stone, SD - Transmission line	1,698,582
5	Big Stone, SD - Construct transmission line	4,085,847
6	Jamestown, ND - Transmission line	5,288,048
7	System Wide - New natural gas generation	2,196,674
8	Beulah, ND - Coyote Station - Boiler lower wall overlay	1,697,827
9	Beulah, ND - Coyote Station - Add overfire air for Nox control	1,180,210
10	Beulah, ND - Coyote Station - Boiler feed pump "A" failure	3,713,369
11	Big Stone, SD - Ellendale, ND - Transmission line	8,001,317
12	Miscellaneous projects under \$1,000,000	12,329,351
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43	TOTAL	64,117,181

**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	653,900,153	653,900,153		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	41,441,421	41,441,421		
4	(403.1) Depreciation Expense for Asset Retirement Costs	146,067	146,067		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,807,939	1,807,939		
7	Other Clearing Accounts	-82,675	-82,675		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	43,312,752	43,312,752		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	33,874,030	33,874,030		
13	Cost of Removal	3,147,070	3,147,070		
14	Salvage (Credit)	1,296,294	1,296,294		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	35,724,806	35,724,806		
16	Other Debit or Cr. Items (Describe, details in footnote):	-1,374,182	-1,374,182		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	660,113,917	660,113,917		

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

20	Steam Production	221,722,599	221,722,599		
21	Nuclear Production				
22	Hydraulic Production-Conventional	3,710,007	3,710,007		
23	Hydraulic Production-Pumped Storage				
24	Other Production	92,925,169	92,925,169		
25	Transmission	108,159,556	108,159,556		
26	Distribution	194,662,831	194,662,831		
27	Regional Transmission and Market Operation				
28	General	38,933,755	38,933,755		
29	TOTAL (Enter Total of lines 20 thru 28)	660,113,917	660,113,917		

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) 12/31/2015	Year/Period of Report 2015/Q4
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, 2014	326,323,066	103,308,022	188,160,340	36,108,725	653,900,153
January 31, 2015	327,937,271	103,466,810	188,572,636	36,365,044	656,341,760
February 28, 2015	329,754,336	103,857,298	189,240,984	36,496,107	659,348,725
March 31, 2015	330,893,260	104,236,790	189,738,105	36,808,750	661,676,905
April 30, 2015	311,317,648	104,207,602	190,406,643	37,155,483	643,087,376
May 31, 2015	313,099,273	104,744,290	190,902,804	37,381,544	646,127,911
June 30, 2015	314,828,255	105,293,503	191,557,049	37,669,476	649,348,284
July 31, 2015	316,507,973	105,812,690	192,437,841	37,955,657	652,714,161
August 31, 2015	315,573,646	106,234,692	193,111,946	38,150,138	653,070,422
September 30, 2015	317,296,309	106,717,241	193,717,263	38,294,615	656,025,428
October 31, 2015	318,936,885	107,141,899	193,447,456	38,566,441	658,092,681
November 30, 2015	317,538,373	107,682,552	194,144,348	38,757,826	658,123,099
December 31, 2015	318,357,775	108,159,556	194,662,831	38,933,755	660,113,917
13-month average for rate-making	319,874,159	105,450,996	191,546,173	37,587,966	654,459,294

\* 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				
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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
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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 (Mo, Da, Yr) 12/31/2015	Year/Period of Report End of <u>2015/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)	9,624,428	12,309,141	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)	5,779,545	5,955,359	Production
8	Transmission Plant (Estimated)	4,354,830	5,153,618	Various
9	Distribution Plant (Estimated)	7,995,012	7,723,909	Various
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	293,737	285,207	Fleet Service
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	18,423,124	19,118,093	
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)	28,047,552	31,427,234	

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) 12/31/2015	Year/Period of Report 2015/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, 2014	5,779,545
January 31, 2015	5,863,187
February 28, 2015	5,930,583
March 31, 2015	5,931,639
April 30, 2015	6,002,739
May 31, 2015	5,995,693
June 30, 2015	5,992,459
July 31, 2015	6,012,898
August 31, 2015	6,028,889
September 30, 2015	6,045,986
October 31, 2015	6,043,940
November 30, 2015	5,976,406
December 31, 2015	5,955,359
13-month average for rate-making	5,966,102

**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, 2014	4,354,830
January 31, 2015	4,940,563
February 28, 2015	5,000,088
March 31, 2015	5,081,969
April 30, 2015	5,077,622
May 31, 2015	5,146,515
June 30, 2015	5,141,535
July 31, 2015	5,007,583
August 31, 2015	5,057,102
September 30, 2015	5,129,206
October 31, 2015	5,105,538
November 30, 2015	5,174,042
December 31, 2015	5,153,618
13-month average for rate-making	5,028,478

**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, 2014	7,995,012

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) 12/31/2015	Year/Period of Report 2015/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

January 31, 2015	7,807,109
February 28, 2015	7,766,891
March 31, 2015	7,968,902
April 30, 2015	8,322,397
May 31, 2015	7,856,213
June 30, 2015	8,243,744
July 31, 2015	8,059,694
August 31, 2015	8,006,933
September 30, 2015	7,837,367
October 31, 2015	7,710,450
November 30, 2015	7,773,314
December 31, 2015	7,723,909
13-month average for rate-making	7,928,610

**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, 2014	293,737	
January 31, 2015	289,692	
February 28, 2015	253,922	
March 31, 2015	262,924	
April 30, 2015	267,159	
May 31, 2015	274,927	
June 30, 2015	275,990	
July 31, 2015	294,174	
August 31, 2015	301,726	
September 30, 2015	292,046	
October 31, 2015	297,074	
November 30, 2015	289,364	
December 31, 2015	285,207	
13-month average for rate-making	282,919	

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		2016	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	37,041.00		15,310.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	South Carolina Public	500.00	168,188		
10	Service Authority				
11					
12					
13					
14					
15	Total	500.00	168,188		
16					
17	Relinquished During Year:				
18	Charges to Account 509	7,965.00	108,771		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	29,576.00	59,417	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	23		
45	Gains	202.96	23		
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.

2017		2018		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		445,863.00		1
								2
								3
				14,054.00		14,054.00		4
								5
								6
								7
						500.00	168,188	8
								9
								10
								11
								12
								13
						500.00	168,188	14
								15
								16
						7,965.00	108,771	17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
14,054.00		14,054.00		379,458.00		452,452.00	59,417	29
								30
								31
								32
								33
								34
								35
202.96		202.96		9,945.16		10,757.00		36
				405.93		405.93		37
								38
				202.96		405.92		39
202.96		202.96		10,148.13		10,757.01		40
								41
								42
								43
				202.96	6	405.92		29 44
				202.96	6	405.92		29 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) 12/31/2015	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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

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

**Schedule Page: 228 Line No.: 1 Column: d**

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

**Schedule Page: 228 Line No.: 18 Column: b**

Includes 1,140 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		2016	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	876.00		876.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	412.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	464.00		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				

Name of Respondent  
Otter Tail Power Company

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

Date of Report  
(Mo, Da, Yr)  
12/31/2015

Year/Period of Report  
End of 2015/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

- 6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
- 7. Report on Lines 8-14 the names of vendors/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.

2017		2018		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						1,752.00		1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						412.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
						1,340.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
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								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) 12/31/2015	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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

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

**Schedule Page: 229 Line No.: 1 Column: d**

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

Name of Respondent

Otter Tail Power Company

This Report Is:

(1)  An Original

(2)  A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2015

Year/Period of Report

End of 2015/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Not applicable					
2						
3						
4						
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16						
17						
18						
19						
20	TOTAL					

Name of Respondent  
Otter Tail Power Company

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

Date of Report  
(Mo, Da, Yr)  
12/31/2015

Year/Period of Report  
End of 2015/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	Big Stone II Canceled Project -MN					
22	(MN PUC Order issued 04-25-11)					
23	Generation	1,060,461		See note	-592,346	468,114
24						
25	Big Stone II Canceled Project -MN					
26	(MN PUC Order issued 04-25-11)					
27	Transmission	2,738,853	208,490	419	-15,074	3,093,678
28						
29	Big Stone II Canceled Project -SD					
30	(SD PUC Order issued 02-11-10)					
31	Generation	610,353		407	-100,332	510,021
32						
33	Big Stone II Canceled Project -SD					
34	(SD PUC Order issued 04-30-13)					
35	Transmission	232,957				232,957
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	4,642,624	208,490		-707,752	4,304,770

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) 12/31/2015	Year/Period of Report 2015/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

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

See footnote 2 of the Notes to Financial Statements, "Rate and Regulatory Matters," for detailed information about the Big Stone II project.

**Schedule Page: 230 Line No.: 23 Column: d**

Accounts 407 and 419 were used.

**Schedule Page: 230 Line No.: 27 Column: c**

Amount of discount previously recognized that was reversed in 2015.

**Schedule Page: 230 Line No.: 35 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	<b>Transmission Studies</b>				
2	Clearbrook West Interconnection	8,498	456		
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	<b>Generation Studies</b>				
22	G736-Crowned Ridge	15,192	456	14,952	456
23	Courteney Wind	264	456	281	456
24					
25					
26					
27					
28					
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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	2,086,506	1,246,428	282	1,877,910	1,455,024
4						
5	Asset Retirement Obligation Capitalized					
6	Hoot Lake Plant	1,789,791	137,721			1,927,512
7	Big Stone Plant	438,911	72,116			511,027
8	Coyote Station	1,969,943	201,309			2,171,252
9	Wind Generation - Langdon	415,410	24,706	407.4	2,332	437,784
10	Wind Generation - Ashtabula	299,150	24,546	407.4	1,981	321,715
11	Wind Generation - Luverne	276,403	25,726			302,129
12						
13	Derivatives-Marked to Market Losses	13,888,420	15,595,924	242 & 253	14,890,940	14,593,404
14						
15	MISO Schedules 26 & 26A Accrual	3,392,204	412,812	See Note	2,751,562	1,053,454
16						
17	MN Renewable Resource Rider	68,361				68,361
18	ND Renewable Resource Rider		1,753,120	See Note	487,346	1,265,774
19						
20	ESSRP	3,328,712	32,151	228.3	350,273	3,010,590
21						
22	Pension	98,239,998	10,927,938	228.3	6,864,481	102,303,455
23						
24	MN Transmission Revenue Rider	3,397,758	920,549	See Note	3,742,241	576,066
25	ND Transmission Revenue Rider	859,236	83,773	See Note	943,009	
26	SD Transmission Revenue Rider		32,850			32,850
27						
28	MN Environmental Cost Recovery Rider	185,694	451,216	See Note	636,910	
29	ND Environmental Cost Recovery Rider	705,323	628,662	See Note	1,333,985	
30	SD Environmental Cost Recovery Rider	37,895	85,705	See Note	123,600	
31						
32	Post Retirement Medical Benefits	7,421,039		228.3	6,003,140	1,417,899
33						
34	Conservation Improvement Program - MN	8,231,185	5,820,962	186	5,558,916	8,493,231
35	Energy Efficiency Program - SD	111,762	252,923	186	181,329	183,356
36						
37	Rate Case Expense Deferral		290,748			290,748
38						
39						
40						
41						
42	See footnote 3 in Notes to Financial Statements					
43	for amortization periods.					
44	<b>TOTAL</b>	<b>147,143,701</b>	<b>39,021,885</b>		<b>45,749,955</b>	<b>140,415,631</b>

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) 12/31/2015	Year/Period of Report 2015/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.: 28 Column: d**

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

**Schedule Page: 232 Line No.: 29 Column: d**

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

**Schedule Page: 232 Line No.: 30 Column: d**

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

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		6,105,445	182.3	6,105,445	
3						
4	Energy Efficiency Program - SD		371,902	182.3	371,902	
5						
6	Purchase Card Accrual	144,583	1,933,558	186	2,078,141	
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	144,583				

**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	226,282	226,283
4	Medical Insurance Reserve		
5	Injuries and Damages Reserve		
6	See Note Below	107,225,793	138,634,382
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	107,452,075	138,860,665
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)	107,452,075	138,860,665

**Notes**

	Balance at Beginning of Year	Balance at End of Year
	-----	-----
Post Retirement Benefits	20,213,258	20,750,054
Executive Supplemental Pension	4,647,369	4,320,986
Reserve for Bad Debts	316,338	328,485
Accrued Vacation Pay	1,667,394	1,661,373
Capitalized Int. on Construction	5,238,008	5,453,637
Post Employment Benefits	39,731	219,208
Incentive Plans	88,559	331,328
Nonqualified Retirement Savings	276,642	277,316
Federal NOL Carryforward	0	24,207,827
Reserve for Loan Pools	8,608	6,933
Property Damage Reserves	0	(110,582)
Capitalized A & G	3,190,560	2,855,688
Customer Rebates Capitalized	97,183	125,956
Stock Incentives	51,150	43,862
CIAC Capitalized	147,098	124,465
BSII Discount	342,945	266,851
Unicap Adjustment	31,622	39,773
Medicare Part D	425,633	477,347
Research Credit Carryforward	247,069	329,514
Charitable Contributions	0	237,330
Severance Settlement	102,540	(333)
Flow-Through Items	167,383	137,860
State NOL Carryforward	4,530,389	4,214,577
Wind Energy Income Tax Credits-ND	41,783,354	41,325,966
ASC 740 Unamortized ITC	1,549,248	1,109,433
ASC 740 Recognition of Regulatory Assets (Liab.)	3,300,889	3,961,768
Wind Production Tax Credit Deferral (Asset)	18,762,822	25,937,759
	-----	-----
	107,225,793	138,634,382

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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CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.

4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.

5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.

Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
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	296,261,391
2	Additional parent investment	43,727,575
3		
4		
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40	TOTAL	339,988,966

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) 12/31/2015	Year/Period of Report End of <u>2015/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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						32
				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) 12/31/2015	Year/Period of Report 2015/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)	48,370,455
2		
3		
4	Taxable Income Not Reported on Books	
5	Interest Capitalized on Construction	1,133,514
6	Net Gain from Property Retirements	1,385,795
7	Miscellaneous Taxable Items	9,000
8	Conservation Improvement Programs	-1,766,067
9	Deductions Recorded on Books Not Deducted for Return	
10	Add Back Federal Income Taxes (Includes Deferreds & ITC Adj)	16,066,841
11	Provision for Reserves	7,662,768
12	Miscellaneous Unallowed Deductions	68,383,552
13		
14	Income Recorded on Books Not Included in Return	
15	Tax Exempt Interest	4,495
16	Wind Rider Revenue	8,409,176
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Excess Tax Depreciation Over Book Depreciation	129,911,058
21	Removal Costs	5,262,893
22	Charges to Reserves	5,923,207
23	Leveraged ESOP Deduction	1,713,452
24	Sec 481(a) Cap to Repair Basis Adjustment	
25	Miscellaneous Other Deductions	59,161,082
26		
27	Federal Tax Net Income	-69,139,505
28	Show Computation of Tax:	
29	Federal Tax	-24,198,827
30	Tax (Credits) and Adjustments	-85,909
31	Prior Period Adjustments	308,083
32	Transfer Net Operating Loss to Deferred Carryforward	24,207,827
33	Total Federal Income Tax	231,174
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

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) 12/31/2015	2015/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 2015. The other members of the affiliated group and their respective federal income tax provisions are as follows:

1	Otter Tail Corporation-Corporate	(4,816,506)
2	Varistar Corporation	(182,908)
3	DMI Industries, Inc.	122,992
4	BTD Manufacturing, Inc.	749,299
5	Northern Pipe Products, Inc.	3,136,169
6	Vinyltech Corporation	3,914,834
7	Otter Tail Energy Services Company	0
8	T. O. Plastics, Inc.	1,059,096
9	Shrco, Inc. (formerly ShoreMaster, Inc.)	(253,358)
10	Galva Foam Marine Industries, Inc.	(94,907)
11	Otter Tail Assurance Limited	259,830
12	Aevenia, Inc.	4,279,820
13	Foley Company	(2,034,592)
14	SLI, Inc. (formerly Shoreline Industries, Inc.)	0
15	ASI, Inc. (formerly Aviva Sports, Inc.)	(75,247)
16	Miller Welding & Iron Works, Inc.	(1,698,033)
	Total	4,366,487
		=====

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			-24,207,826	-24,207,828	
3	Unemployment	628		35,681	35,647	
4	FICA			4,668,403	4,668,403	
5						
6	MINNESOTA					
7	Property	8,175,002		9,001,432	8,101,433	
8	Income			1,188,364	1,188,364	
9	Unemployment	870		36,026	36,242	
10						
11	NORTH DAKOTA					
12	Property	2,174,999		2,371,112	2,171,112	
13	Income			-1,201,327	-1,201,327	
14	Unemployment	698		23,282	23,086	
15	Coal Conversion	139,111		661,353	653,473	
16						
17	SOUTH DAKOTA					
18	Property	1,674,999		1,531,756	1,506,756	
19	Unemployment	65		8,703	8,341	
20						
21	OTHER STATES					
22	Income					
23	Railcar	14,224		24,733	28,353	
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	12,180,596		-5,858,308	-6,987,945	

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
		-1,845,914			-22,361,914	2
662					35,681	3
					4,668,403	4
						5
						6
9,075,001		9,001,432				7
		-291,834			1,480,200	8
654					36,026	9
						10
						11
2,375,000		2,310,224			60,888	12
		-102,618			-1,098,709	13
894					23,282	14
146,991		661,353				15
						16
						17
1,700,000		1,531,756				18
427					8,703	19
						20
						21
						22
10,604					24,733	23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
13,310,233		11,264,399			-17,122,707	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) 12/31/2015	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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

Account 409.2: 2,077,088; Other: (24,439,002)

**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: 291,840; Other: 1,188,360

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

Account 184

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

Account 921: 53,484; Account 408.2: 7,404

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

Account 409.2: 102,621; Other: (1,201,330)

**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

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%	25,152,997			411.4	1,306,824	
3	4%						
4	7%						
5	10%	1,231,042			411.4	571,170	
6							
7							
8	TOTAL	26,384,039				1,877,994	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
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47							
48							

Name of Respondent  
Otter Tail Power Company

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

Date of Report  
(Mo, Da, Yr)  
12/31/2015

Year/Period of Report  
End of 2015/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
23,846,173	25 Years		2
			3
			4
659,872	33.3 Years		5
			6
			7
24,506,045			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
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			24
			25
			26
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			31
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			33
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			44
			45
			46
			47
			48

Name of Respondent  
Otter Tail Power Company

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

Date of Report  
(Mo, Da, Yr)  
12/31/2015

Year/Period of Report  
End of 2015/Q4

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	974,660	456	298,415	387,908	1,064,153
2	Payroll Clearing		184	513,403	514,677	1,274
3	Discontinued Mark-to-Market				10,530,480	10,530,480
4	Forward Energy Contracts					
5	(Amortization thru Dec 2020)					
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
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39						
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41						
42						
43						
44						
45						
46						
47	TOTAL	974,660		811,818	11,433,065	11,595,907

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			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent

Otter Tail Power Company

This Report Is:

(1)  An Original

(2)  A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2015

Year/Period of Report

End of 2015/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (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
							11
							12
							13
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							20
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NOTES (Continued)

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) 12/31/2015	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

**Schedule Page: 272 Line No.: 3 Column: b**

Not applicable. OTP has a zero balance in account 281.

**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	287,721,110	62,958,037	13,485,715
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	287,721,110	62,958,037	13,485,715
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	287,721,110	62,958,037	13,485,715
10	Classification of TOTAL			
11	Federal Income Tax	246,536,124	54,279,200	11,049,684
12	State Income Tax	41,184,985	8,678,837	2,436,031
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
	137,974			See Note	-284,124	336,771,334	2
							3
							4
	137,974				-284,124	336,771,334	5
							6
							7
							8
	137,974				-284,124	336,771,334	9
							10
	114,695				-238,352	289,412,593	11
	23,279				-45,772	47,358,740	12
							13

NOTES (Continued)

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) 12/31/2015	2015/Q4
FOOTNOTE DATA			

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

182.3 Adjustment due to ASC740

**Schedule Page: 274 Line No.: 9 Column: k**

Amortization of Loss on Reacquired Debt (pre holdco)	(740,167)
Big Stone II Deferred Costs	(1,870,750)
Retirements Method Change	195,974
South Dakota Flow Thru-Overheads	(15,867)
Prepaid Expenses	(301,420)
ADR Repair Allowance	(2,278,112)
Sec 172 & 174 R&D Deduction	(3,556,003)
Highway Powerline Relocation	49,028
AFUDC on Debt	(3,112,293)
Capitalized Overheads	(82,629)
Repairs Deduction - Basis Adjustments	(15,474,420)
Sec 481(a) Cap to Repair Basis Adjustments (PV)	4,373,048
Excess Tax Over Book Depreciation	(299,459,281)
North Dakota Investment Tax Credit - Federal Impacts	(11,542,931)
ASC 740 (SFAS 109) ADIT Credits - Property	(2,956,160)
	-----
Total	(336,771,334)
	=====

**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	17,246,153	14,241,339	14,677,585
5				
6	Accum. Deferred Income Tax			
7	Nonutility & Other	935,008		
8				
9	TOTAL Electric (Total of lines 3 thru 8)	18,181,161	14,241,339	14,677,585
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)	18,181,161	14,241,339	14,677,585
20	Classification of TOTAL			
21	Federal Income Tax	14,198,904	11,122,029	11,462,723
22	State Income Tax	3,982,257	3,119,310	3,214,862
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
				See Note	195,342	17,005,249	4
							5
							6
694,265	726					1,628,547	7
							8
694,265	726				195,342	18,633,796	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
694,265	726				195,342	18,633,796	19
							20
542,199	567				152,556	14,552,398	21
152,066	159				42,786	4,081,398	22
							23

NOTES (Continued)

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) 12/31/2015	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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

Account credited: 228.3  
Adjustment due to ASC715-60 (118,179)

Account debited: 182.3  
Adjustment due to ASC740 313,521  
-----  
Total 195,342  
=====

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

Deferred taxes related to CIP costs and mark to market accounting.

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

Pensions (13,774,878)  
Conservation Improvement Program - MN & SD - Net (BTL) (1,628,547)  
Wind Rider Revenue (731,692)  
Transmission Rider Revenue (182,430)  
Environmental Rider Revenue 508,294  
Big Stone II Recovery Costs (390)  
Deferred State NOL's - Federal Haircut (1,480,923)  
Regulatory Adjustments 1,117,402  
ASC 740 (SFAS 109) ADIT Credits - Non-Property (2,460,632)  
-----  
Total (18,633,796)  
=====

**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	1,549,249	190	439,815		1,109,434
2	ASC 740					
3						
4	Minnesota Portion of Gain on Sale	105,948	407.4	5,577		100,371
5	of Wahpeton Division Office					
6						
7	Derivatives - Mark to Market	257,106	175	3,928,637	3,671,531	
8						
9	SD Transmission Revenue Rider	48,106	See Note	154,328	106,222	
10	ND Transmission Revenue Rider				131,437	131,437
11						
12	ND Renewable Resource Revenue Rider	1,018,113	See Note	2,223,839	1,274,085	68,359
13						
14	MN Future Rate Case Expense Accrual	783,865			495,072	1,278,937
15						
16	ND Big Stone Plant II	147,360	See Note	147,360		
17						
18	SD Environmental Revenue Rider		See Note	91,621	276,541	184,920
19	ND Environmental Revenue Rider		See Note	650,773	971,643	320,870
20	MN Environmental Revenue Rider		See Note	231,724	1,008,861	777,137
21						
22	SD Margin Sharing	24,546	See Note	24,546		
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33	See Footnote 3 in Notes to Financial					
34	Statements for amortization periods.					
35						
36						
37						
38						
39						
40						
41	<b>TOTAL</b>	<b>3,934,293</b>		<b>7,898,220</b>	<b>7,935,392</b>	<b>3,971,465</b>

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) 12/31/2015	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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

Accounts were 440, 442, 444, and 445.

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

Accounts were 440, 442, 444, and 445.

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

Accounts were 440, 442, 444, and 445.

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

Accounts were 440, 442, 444, and 445.

**Schedule Page: 278 Line No.: 19 Column: c**

Accounts were 440, 442, 444, and 445.

**Schedule Page: 278 Line No.: 20 Column: c**

Accounts were 440, 442, 444, and 445.

**Schedule Page: 278 Line No.: 22 Column: c**

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	116,279,070	119,730,343
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	138,431,230	136,930,327
5	Large (or Ind.) (See Instr. 4)	98,305,377	95,036,889
6	(444) Public Street and Highway Lighting	3,670,700	3,629,391
7	(445) Other Sales to Public Authorities	3,097,480	3,120,689
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	359,783,857	358,447,639
11	(447) Sales for Resale	2,498,622	11,159,834
12	TOTAL Sales of Electricity	362,282,479	369,607,473
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	362,282,479	369,607,473
15	Other Operating Revenues		
16	(450) Forfeited Discounts	690,605	628,802
17	(451) Miscellaneous Service Revenues	385,821	416,052
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	522,340	516,573
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	6,856,260	8,897,924
22	(456.1) Revenues from Transmission of Electricity of Others	28,798,406	22,068,639
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	37,253,432	32,527,990
27	TOTAL Electric Operating Revenues	399,535,911	402,135,463

**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
1,272,912	1,386,104	103,039	102,641	2
				3
1,588,296	1,688,771	26,725	26,651	4
1,665,699	1,551,483	57	56	5
25,851	26,218	408	402	6
40,846	42,486	593	590	7
				8
				9
4,593,604	4,695,062	130,822	130,340	10
115,860	775,834			11
4,709,464	5,470,896	130,822	130,340	12
				13
4,709,464	5,470,896	130,822	130,340	14

Line 12, column (b) includes \$ 88,755 of unbilled revenues.

Line 12, column (d) includes -2,927 MWH relating to unbilled revenues

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) 12/31/2015	Year/Period of Report 2015/Q4
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)	\$385,821	\$416,052
	-----	-----
Total	\$385,821	\$416,052
	=====	=====

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

Description of Revenue	Current Year	Prior Year
Sale of steam	\$ 1,115,569	\$ 2,444,647
Wind generation development	3,009,517	452,777
Integrated transmission deficiency payments	1,621,282	3,581,519
All others (under \$250,000 each)	1,109,892	2,418,981
	-----	-----
Total	\$ 6,856,260	\$ 8,897,924
	=====	=====

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					
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				

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential-440					
2	Residential Service					
3	9.01	891,154	94,599,989	97,335	9,156	0.1062
4						
5	Residential Service (Ctrl'd Demand					
6	9.02	145,583	11,524,865	6,255	23,275	0.0792
7						
8	Water Heating Ctrl'd (Off-Peak)					
9	14.01	38,488	3,031,407	16,009	2,404	0.0788
10				-16,009		
11	Controlled Service					
12	14.04,14.05,14.06,14.07	187,974	10,042,252	13,307	14,126	0.0534
13				-13,307		
14	Fixed Time of Delivery Service					
15	14.07	5,343	228,286	393	13,595	0.0427
16				-393		
17	Outdoor lighting-energy only					
18	11.03	62	6,190	10	6,200	0.0998
19				-10		
20	Outdoor Lighting					
21	11.04	3,869	574,023	328	11,796	0.1484
22				-328		
23	Small power producer rider					
24	12.01		382	9		
25				-9		
26	Conservation Imp Prog Rev		-1,253,682			
27	Environmental Rider Rev		-787,501			
28	Transmission Cost Recvy		-1,649,046			
29	Renewable Resource Rider		749,045			
30	Fuel Clause Adjustment Rec		-804,076			
31	MN Rate Case Rev Reduction		-129,708			
32						
33	SUBTOTAL Billed	1,272,473	116,132,426	103,590	12,284	0.0913
34	Unbilled Rev (See Instr. 6)	439	146,644			0.3340
35	TOTAL - 440	1,272,912	116,279,070	103,590	12,288	0.0913
36						
37	Column D Lines 9,12,15,18,21&24					
38	customers are also served					
39	under other residential service.					
40						
41	TOTAL Billed	4,596,531	359,695,102	134,135	34,268	0.0783
42	Total Unbilled Rev.(See Instr. 6)	-2,927	88,755	0	0	-0.0303
43	TOTAL	4,593,604	359,783,857	134,135	34,246	0.0783

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	745,898	74,948,004	24,665	30,241	0.1005
4						
5	Farm Service					
6	9.03	69,455	6,513,270	2,809	24,726	0.0938
7						
8	Large General Service					
9	10.03	611,580	44,919,740	354	1,727,627	0.0734
10						
11	Real Time Pricing Rider					
12	14.02	33,601	1,282,553	2	16,800,500	0.0382
13						
14	Large Gen. Srv. (Time of Day)					
15	10.05	915,249	58,853,523	91	10,057,681	0.0643
16						
17	Large General Service Rider					
18	14.03	81,041	4,026,554	14	5,788,643	0.0497
19						
20	Water Heating Ctrlld (Off-Peak)					
21	14.01	2,071	155,273	509	4,069	0.0750
22				-509		
23	Controlled Service					
24	14.04,14.05,14.06,14.07	191,002	8,764,252	4,988	38,292	0.0459
25				-4,988		
26	Fixed Time of Delivery Service					
27	14.07	22,618	917,482	574	39,404	0.0406
28				-574		
29	Irrigation Service					
30	11.02	5,885	504,958	351	16,766	0.0858
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	4,596,531	359,695,102	134,135	34,268	0.0783
42	Total Unbilled Rev.(See Instr. 6)	-2,927	88,755	0	0	-0.0303
43	TOTAL	4,593,604	359,783,857	134,135	34,246	0.0783

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	10.04	562,289	43,527,215	616	912,807	0.0774
4						
5	Outdoor Lighting - Energy Only					
6	11.03	1,970	172,722	254	7,756	0.0877
7				-254		
8	Outdoor Lighting					
9	11.04	14,463	1,988,620	261	55,414	0.1375
10				-261		
11	Standby Service - Option A Firm					
12	11.01	132	16,398	5	26,400	0.1242
13						
14	Small Power Producer Rider					
15	12.01		719	23		
16				-23		
17	Conservation Imp Prog Rev		-3,226,540			
18	Environmental Rider Rev		-1,386,166			
19	Transmission Cost Recvy		-4,190,161			
20	Renewable Resource Rider		1,428,553			
21	Fuel Clause Adjustment Rec		-2,072,232			
22	MN Rate Case Rev Reduction		-358,500			
23						
24	SUBTOTAL Billed	3,257,254	236,786,237	28,907	112,680	0.0727
25	Unbilled Rev (See Instr. 6)	-3,259	-49,630			0.0152
26	TOTAL - 442	3,253,995	236,736,607	28,907	112,568	0.0728
27						
28						
29						
30	Column D Lines 6,9 & 15					
31	customers are also served under					
32	other commerical service.					
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,596,531	359,695,102	134,135	34,268	0.0783
42	Total Unbilled Rev.(See Instr. 6)	-2,927	88,755	0	0	-0.0303
43	TOTAL	4,593,604	359,783,857	134,135	34,246	0.0783

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	Streetlighting - 444					
2	Outdoor Lighting-Energy Only					
3	11.03	7,311	615,431	266	27,485	0.0842
4				-266		
5	Outdoor lighting					
6	11.04	18,565	3,138,049	349	53,195	0.1690
7						
8	Conservation Imp Prog Rev		-19,887			
9	Environmental Rider Rev		-20,066			
10	Transmission Cost Recvy		-31,457			
11	Renewable Resource Rider		16,237			
12	Fuel Clause Adjustment Rec		-22,474			
13	MN Rate Case Rev Reduction		-2,556			
14						
15	Subtotal billed	25,876	3,673,277	349	74,143	0.1420
16	Unbilled Revenue	-25	-2,577			0.1031
17	TOTAL - 444	25,851	3,670,700	349	74,072	0.1420
18						
19	Other Public Authority-445					
20	Pumping and Sirens					
21	11.05,11.06	40,928	3,218,581	1,289	31,752	0.0786
22						
23	Conservation Imp Prog Rev		-38,319			
24	Environmental Rider Rev		-18,106			
25	Transmission Cost Recvy		-52,134			
26	Renewable Resource Rider		21,693			
27	Fuel Clause Adjustment Rec		-24,245			
28	MN Rate Case Rev Reduction		-4,308			
29						
30	Subtotal	40,928	3,103,162	1,289	31,752	0.0758
31	Unbilled Revenue	-82	-5,682			0.0693
32	TOTAL - 445	40,846	3,097,480	1,289	31,688	0.0758
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	4,596,531	359,695,102	134,135	34,268	0.0783
42	Total Unbilled Rev.(See Instr. 6)	-2,927	88,755	0	0	-0.0303
43	TOTAL	4,593,604	359,783,857	134,135	34,246	0.0783

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) 12/31/2015	2015/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	\$ 2,218,370
9.02	Residential service (control demand)	188,114
14.01	Water heating - controlled (off-peak)	139,931
14.04,14.05,14.06,14.07	Controlled service	323,743
14.07	Fixed time of delivery service	18,030
11.03	Outdoor lighting- energy only	89
11.04	Outdoor lighting	10,126
		-----
Total residential		\$ 2,898,403

Commercial and industrial - 442

10.01, 10.02	General service	\$ 1,657,498
9.03	Farm service	202,871
10.03	Large general service	(1,338,745)
14.02	Real time pricing rider	-
10.05	Large general service (time of day)	2,426,174
14.03	Large general service rider	219,679
14.01	Water heating - controlled (off-peak)	12,429
14.04,14.05,14.06,14.07	Controlled service	313,461
14.07	Fixed time of delivery service	62,475
11.02	Irrigation service	5,018
10.04	Commercial time of use	5,712,132
11.03	Outdoor lighting - energy only	5,800
11.04	Outdoor lighting	25,468
11.01	Standby service-option A firm	(368)
		-----
Total commercial and industrial		\$ 9,303,892

Streetlighting - 444

11.03	Outdoor lighting - energy only	\$ 16,777
11.04	Outdoor lighting	46,228
		-----
Total streetlighting		\$ 63,005

Other public authority - 445

11.05,11.06	Pumping and sirens	\$ 107,404
		-----

Total		\$12,372,704
		=====

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	0.116	NA	NA
3	Newfolden, MN	RQ	174	0.510	NA	NA
4	Nielsville, MN	RQ	175	0.54	NA	NA
5	Shelly, MN	RQ	176	0.188	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
	<b>Total</b>			<b>0</b>	<b>0</b>	<b>0</b>

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
361	6,303	11,770	3,253	21,326	2
2,335	28,861	79,856	22,096	130,813	3
95	4,100	2,871	813	7,784	4
686	14,390	23,643	6,640	44,673	5
					6
					7
112,383		2,294,026		2,294,026	8
					9
					10
					11
					12
					13
					14
3,477	53,654	118,140	32,802	204,596	
112,383	0	2,294,026	0	2,294,026	
<b>115,860</b>	<b>53,654</b>	<b>2,412,166</b>	<b>32,802</b>	<b>2,498,622</b>	

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) 12/31/2015	Year/Period of Report 2015/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	<b>1. POWER PRODUCTION EXPENSES</b>		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,692,309	1,642,981
5	(501) Fuel	42,347,510	64,548,005
6	(502) Steam Expenses	3,380,097	3,215,141
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,043,486	2,432,216
10	(506) Miscellaneous Steam Power Expenses	5,258,516	4,972,804
11	(507) Rents	3,169	448
12	(509) Allowances	108,771	
13	<b>TOTAL Operation (Enter Total of Lines 4 thru 12)</b>	<b>54,833,858</b>	<b>76,811,595</b>
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	811,657	773,644
16	(511) Maintenance of Structures	1,221,739	708,960
17	(512) Maintenance of Boiler Plant	6,587,242	7,236,561
18	(513) Maintenance of Electric Plant	3,051,732	4,755,818
19	(514) Maintenance of Miscellaneous Steam Plant	1,532,144	1,555,138
20	<b>TOTAL Maintenance (Enter Total of Lines 15 thru 19)</b>	<b>13,204,514</b>	<b>15,030,121</b>
21	<b>TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 &amp; 20)</b>	<b>68,038,372</b>	<b>91,841,716</b>
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	<b>TOTAL Operation (Enter Total of lines 24 thru 32)</b>		
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	<b>TOTAL Maintenance (Enter Total of lines 35 thru 39)</b>		
41	<b>TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 &amp; 40)</b>		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	5,736	16,579
45	(536) Water for Power		
46	(537) Hydraulic Expenses	21,867	39,285
47	(538) Electric Expenses	49,063	46,139
48	(539) Miscellaneous Hydraulic Power Generation Expenses	12,569	22,345
49	(540) Rents		
50	<b>TOTAL Operation (Enter Total of Lines 44 thru 49)</b>	<b>89,235</b>	<b>124,348</b>
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	430	4,134
54	(542) Maintenance of Structures	118	1,155
55	(543) Maintenance of Reservoirs, Dams, and Waterways	253,790	221,334
56	(544) Maintenance of Electric Plant	4,457	18,516
57	(545) Maintenance of Miscellaneous Hydraulic Plant	390	2,089
58	<b>TOTAL Maintenance (Enter Total of lines 53 thru 57)</b>	<b>259,185</b>	<b>247,228</b>
59	<b>TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 &amp; 58)</b>	<b>348,420</b>	<b>371,576</b>

**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	243,994	192,311
63	(547) Fuel	793,888	3,494,522
64	(548) Generation Expenses	2,141,702	2,493,274
65	(549) Miscellaneous Other Power Generation Expenses	667,764	620,963
66	(550) Rents	570,350	570,101
67	TOTAL Operation (Enter Total of lines 62 thru 66)	4,417,698	7,371,171
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	55,466	23,033
70	(552) Maintenance of Structures	62,819	37,245
71	(553) Maintenance of Generating and Electric Plant	681,184	790,197
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	85,607	142,449
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	885,076	992,924
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	5,302,774	8,364,095
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	78,149,806	65,848,281
77	(556) System Control and Load Dispatching	499,422	445,767
78	(557) Other Expenses	75,119	459,424
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	78,724,347	66,753,472
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	152,413,913	167,330,859
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	509,397	417,353
84			
85	(561.1) Load Dispatch-Reliability	71,570	83,412
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,550,472	2,446,095
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	902,670	721,548
89	(561.5) Reliability, Planning and Standards Development	713,221	615,821
90	(561.6) Transmission Service Studies	341	782
91	(561.7) Generation Interconnection Studies		96
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	284,402	241,017
94	(563) Overhead Lines Expenses	406,001	336,332
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	16,995,586	13,428,393
97	(566) Miscellaneous Transmission Expenses	826,978	680,076
98	(567) Rents	37,889	38,264
99	TOTAL Operation (Enter Total of lines 83 thru 98)	23,298,527	19,009,189
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	217,105	263,031
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	14,396	55,519
104	(569.2) Maintenance of Computer Software	833,601	749,844
105	(569.3) Maintenance of Communication Equipment	62,694	91,291
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,109,533	1,088,198
108	(571) Maintenance of Overhead Lines	1,541,400	2,559,518
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	2,975	155
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,781,704	4,807,556
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	27,080,231	23,816,745

**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	<b>3. REGIONAL MARKET EXPENSES</b>		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation	710,103	903,791
117	(575.3) Transmission Rights Market Facilitation	15,185	298,199
118	(575.4) Capacity Market Facilitation	1,455	
119	(575.5) Ancillary Services Market Facilitation	23,330	
120	(575.6) Market Monitoring and Compliance	9,134	
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	759,207	1,201,990
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software	265,641	280,611
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)	265,641	280,611
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	1,024,848	1,482,601
132	<b>4. DISTRIBUTION EXPENSES</b>		
133	Operation		
134	(580) Operation Supervision and Engineering	328,199	373,153
135	(581) Load Dispatching	240,934	275,153
136	(582) Station Expenses	258,974	231,893
137	(583) Overhead Line Expenses	319,375	285,535
138	(584) Underground Line Expenses	1,933,240	1,730,479
139	(585) Street Lighting and Signal System Expenses		16,022
140	(586) Meter Expenses	805,861	1,133,101
141	(587) Customer Installations Expenses	191,828	196,638
142	(588) Miscellaneous Expenses	3,311,530	3,136,552
143	(589) Rents	235,262	237,624
144	TOTAL Operation (Enter Total of lines 134 thru 143)	7,625,203	7,616,150
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	755,253	831,421
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	748,264	752,806
149	(593) Maintenance of Overhead Lines	3,330,118	4,287,091
150	(594) Maintenance of Underground Lines	1,005,602	1,027,891
151	(595) Maintenance of Line Transformers	87,213	92,316
152	(596) Maintenance of Street Lighting and Signal Systems	1,055,120	1,060,301
153	(597) Maintenance of Meters	823,318	729,783
154	(598) Maintenance of Miscellaneous Distribution Plant	84,207	113,466
155	TOTAL Maintenance (Total of lines 146 thru 154)	7,889,095	8,895,075
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	15,514,298	16,511,225
157	<b>5. CUSTOMER ACCOUNTS EXPENSES</b>		
158	Operation		
159	(901) Supervision	134,181	125,583
160	(902) Meter Reading Expenses	5,682,033	5,939,271
161	(903) Customer Records and Collection Expenses	5,825,857	6,178,613
162	(904) Uncollectible Accounts	780,001	760,000
163	(905) Miscellaneous Customer Accounts Expenses	369,270	354,679
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	12,791,342	13,358,146

**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	<b>6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES</b>		
166	Operation		
167	(907) Supervision	619,603	811,827
168	(908) Customer Assistance Expenses	7,711,069	6,761,178
169	(909) Informational and Instructional Expenses	507,494	438,081
170	(910) Miscellaneous Customer Service and Informational Expenses	25,962	17,921
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	8,864,128	8,029,007
172	<b>7. SALES EXPENSES</b>		
173	Operation		
174	(911) Supervision	23,411	
175	(912) Demonstrating and Selling Expenses	274,774	260,876
176	(913) Advertising Expenses	671	1,743
177	(916) Miscellaneous Sales Expenses	13,912	229,989
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	312,768	492,608
179	<b>8. ADMINISTRATIVE AND GENERAL EXPENSES</b>		
180	Operation		
181	(920) Administrative and General Salaries	22,271,342	20,845,574
182	(921) Office Supplies and Expenses	6,877,617	8,117,224
183	(Less) (922) Administrative Expenses Transferred-Credit	2,210,241	1,550,302
184	(923) Outside Services Employed	1,777,537	1,208,582
185	(924) Property Insurance	2,059,414	1,987,665
186	(925) Injuries and Damages	2,128,998	2,352,407
187	(926) Employee Pensions and Benefits	3,083,224	2,684,087
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	2,193,553	1,052,165
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	320,655	473,030
192	(930.2) Miscellaneous General Expenses	1,345,237	1,374,483
193	(931) Rents	287,129	272,535
194	TOTAL Operation (Enter Total of lines 181 thru 193)	40,134,465	38,817,450
195	Maintenance		
196	(935) Maintenance of General Plant	1,890,817	2,969,643
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	42,025,282	41,787,093
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	260,026,810	272,808,284

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) 12/31/2015	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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

\$702,099 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**

\$675,907 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.

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

PURCHASED POWER (Account 555)  
(Including power exchanges)

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2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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	Cass County Electric Cooperative	RQ		NA	NA	NA
2	Dakota Valley Electric Cooperative	RQ		NA	NA	NA
3	Whetstone Valley Electric Cooperative	RQ		NA	NA	NA
4	Prairie Lakes Muni Waste	RQ		NA	NA	NA
5	Dakota Magic Casino	RQ		NA	NA	NA
6	Kindred School	RQ		NA	NA	NA
7	Valley Queen Cheese	OS		NA	NA	NA
8	Stevens Community Medical	OS		NA	NA	NA
9	City of Detroit Lakes	OS		NA	NA	NA
10	American Crystal Sugar	OS		NA	NA	NA
11	District 45 Methane	OS		NA	NA	NA
12	Dakota Wind Exchange	OS		NA	NA	NA
13	Hendricks Wind I	OS		NA	NA	NA
14	Borderline Wind	OS		NA	NA	NA
	Total					

PURCHASED POWER (Account 555)  
(Including power exchanges)

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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	Univ. of MN - Morris	OS		NA	NA	NA
2	FPL Energy ND II, LLC	OS		NA	NA	NA
3	FPL Energy ND II, LLC - Curtailment	OS		NA	NA	NA
4	Langdon Wind, LLC	OS		NA	NA	NA
5	Turtle Mountain Community College	OS		NA	NA	NA
6	LacQui Parle School	OS		NA	NA	NA
7	Pembina Border Station	OS		NA	NA	NA
8	Lake Region State College	OS		NA	NA	NA
9	Ashtabula Wind III LLC	OS		NA	NA	NA
10	Ashtabula Wind III LLC - Curtailment	OS		NA	NA	NA
11	MN Co Generation	OS		NA	NA	NA
12	ND Co Generation	OS		NA	NA	NA
13	SD Co Generation	OS		NA	NA	NA
14						
	Total					

PURCHASED POWER (Account 555)  
(Including power exchanges)

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2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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	Missouri River Energy Services RLA	OS		NA	NA	NA
2	Excel Energy RLA	OS		NA	NA	NA
3	Midwest ISO Energy Market	OS		NA	NA	NA
4						
5	Non-Asset Based Cost of Sales					
6	Miscellaneous Energy Market Changes					
7	Other ISO Energy Markets					
8						
9						
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)  
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a 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)	
58,400				503,090		503,090	1
			-80,000			-80,000	2
			1,500,000			1,500,000	3
50,400				725,046		725,046	4
			-63,000			-63,000	5
			-86,625			-86,625	6
			-30,800			-30,800	7
670,850				7,730,384		7,730,384	8
279				26,064	29,637	55,701	9
32,158				1,069,261		1,069,261	10
86,367			727,357	4,719,119	55,316	5,501,792	11
9,928			107,371	576,860		684,231	12
10,608			110,443	595,275		705,718	13
9,127			95,303	488,051		583,354	14
3,283,337			2,402,764	75,662,089	84,953	78,149,806	

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)	
			5,102			5,102	1
72				6,552		6,552	2
			491			491	3
			13,200			13,200	4
			25,920			25,920	5
			45,980			45,980	6
			7,000			7,000	7
			23,760			23,760	8
1,000			1,262	1,500		2,762	9
153				1,536		1,536	10
11,427				535,325		535,325	11
161				5,462		5,462	12
2,357				106,069		106,069	13
1,936				58,072		58,072	14
3,283,337			2,402,764	75,662,089	84,953	78,149,806	

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)	
4,916				270,359		270,359	1
57,278				1,712,612		1,712,612	2
9				282		282	3
75,422				2,958,058		2,958,058	4
541				19,485		19,485	5
54				1,910		1,910	6
1,010				34,997		34,997	7
4,163				131,485		131,485	8
208,295				5,663,799		5,663,799	9
4,715				128,560		128,560	10
127				11,085		11,085	11
62				68		68	12
43				1,514		1,514	13
							14
3,283,337			2,402,764	75,662,089	84,953	78,149,806	

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)	
				405		405	1
-257				-4,643		-4,643	2
1,981,736				47,752,289		47,752,289	3
							4
				-146,054		-146,054	5
				-9,808		-9,808	6
				-11,980		-11,980	7
							8
							9
							10
							11
							12
							13
							14
3,283,337			2,402,764	75,662,089	84,953	78,149,806	

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) 12/31/2015	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

**Schedule Page: 326 Line No.: 2 Column: a**  
January through May 2015

**Schedule Page: 326 Line No.: 3 Column: a**  
January through December 2015

**Schedule Page: 326 Line No.: 5 Column: a**  
June through December 2015

**Schedule Page: 326 Line No.: 6 Column: a**  
June through December 2015

**Schedule Page: 326 Line No.: 7 Column: a**  
June through December 2015

**Schedule Page: 326 Line No.: 9 Column: I**  
Load following charge

**Schedule Page: 326 Line No.: 11 Column: I**  
Nomination charge

**Schedule Page: 326.3 Line No.: 5 Column: a**

The Company records unrealized gains and losses of forward purchases and sales of energy. FERC Order No. 627 states that entities should record unrealized as well as realized gains or losses in accounts 421 or 426.5, as appropriate. This amount represents the non-asset based cost of forward energy sales.

**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				
	<b>TOTAL</b>			

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		1,231	1,177	1
4	(1)	Newfolden, MN		2,816	2,632	2
4	(1)	Nielsville, MN		628	587	3
4	(1)	Shelly, MN		1,708	1,596	4
4	(1)	Fort Totten, ND		355	335	5
4	(1)	Grafton, ND		4,794	4,523	6
4	(1)	Devils Lake, ND		510	477	7
4	(1)	Bottineau, ND		1,133	1,059	8
4	(1)	Wahpeton, ND		8,878	8,336	9
4	(1)	Belcourt, ND		1,260	1,189	10
4	(1)	Oakes, ND		60	57	11
See Footnote	(1)	Various Interconnect		240,137	224,427	12
		(1)		4,152		13
		(1)		-154,230		14
		(1)		3,424		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	116,856	246,395	

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.
8,814			8,814	1
25,536			25,536	2
7,303			7,303	3
16,657			16,657	4
1,485			1,485	5
24,059			24,059	6
6,026			6,026	7
10,809			10,809	8
94,676			94,676	9
27,998			27,998	10
2,021			2,021	11
	227,228		227,228	12
				13
				14
				15
		28,345,794	28,345,794	16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
<b>225,384</b>	<b>227,228</b>	<b>28,345,794</b>	<b>28,798,406</b>	

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) 12/31/2015	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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

Original Service Agreement No. 30 under Otter Tail Power Company FERC Electricc 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 = 287,399

Schedule 1 Firm = 42,980

Schedule 1 Non-firm = 9,244

**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					
18					
19					
20					
21					
22					
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					4,065,313	4,065,313
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						4,065,313	4,065,313

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) 12/31/2015	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

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

Charges in line 1 are for Midwest Independent System Operator Schedule 26 Network Upgrade charges to Otter Tail Power Company from the Midwest Independent System Operator Transmission Expansion Plan costs that were booked in 2015.

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	254,562
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	24,307
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	191,053
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	37,096
6	Directors Fees and Expenses	616,431
7	Miscellaneous Labor Not Provided for Elsewhere	206,040
8	News Release Distribution - Sundog Interactive, Inc.	10,748
9	Energy Innovation Celebration-Great Plains Institute	5,000
10		
11		
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44		
45		
46	TOTAL	1,345,237

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)  
(Except amortization of acquisition adjustments)

- 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).
- 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.
- 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.
- 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			1,496,906		1,496,906
2	Steam Production Plant	8,807,692	149,685			8,957,377
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	515,648				515,648
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	12,132,584	-3,618			12,128,966
7	Transmission Plant	6,389,151				6,389,151
8	Distribution Plant	10,779,201				10,779,201
9	Regional Transmission and Market Operation					
10	General Plant	2,817,145				2,817,145
11	Common Plant-Electric					
12	TOTAL	41,441,421	146,067	1,496,906		43,084,394

B. Basis for Amortization Charges

The \$1,496,906 is amortization of:

Franchises and Consents (302)

\$41,847 for hydro plant licenses with a remaining life of 6.92 years at a 3.21% rate.

Miscellaneous Intangible Plant (303)

\$1,455,059 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	3,313	59.84	-11.80	0.87	SQ	31.07
15	312	29,876	48.79	-11.80	1.61	SQ	31.11
16	314	11,466	44.61	-11.80	1.64	SQ	31.13
17	315	2,679	54.03	-11.80	1.30	SQ	31.09
18	316	998	48.03	-11.40	1.65	SQ	31.11
19							
20	Hoot Lake Plant						
21	311 - Units 2, 3	314	35.51	-14.10	2.99	SQ	6.44
22	312 - Units 2, 3	15,470	17.75	-14.10	7.91	SQ	6.45
23	314 - Units 2, 3	1,865	29.81	-14.10	4.70	SQ	6.44
24	315 - Units 2, 3	346	24.25	-14.10	4.13	SQ	6.44
25	316 - Units 2, 3	300	15.46	-14.10	6.56	SQ	6.45
26							
27	Coyote Plant						
28	311	9,916	52.64	-8.60	1.45	SQ	23.48
29	312	30,993	49.16	-8.60	1.61	SQ	26.49
30	314	11,691	39.29	-8.60	2.17	SQ	26.52
31	315	4,203	47.92	-8.60	1.66	SQ	26.50
32	316	972	39.59	-8.30	2.23	SQ	26.51
33							
34	STEAM PROD	124,402					
35							
36	HYDRO PRODUCTION						
37	Hoot Lake Hydro						
38	331	1	60.89		0.24	SQ	7.42
39	332	47	29.81		2.11	SQ	7.43
40	333	11	35.93		1.44	SQ	7.42
41	334	5	30.56		1.97	SQ	7.43
42	335	41	8.90		11.21	SQ	7.43
43							
44	Wright Hydro						
45	331	4	30.57		2.98	SQ	7.43
46	332	666	19.47		10.07	SQ	7.43
47	333	151	18.74		3.73	SQ	7.43
48	334	76	17.72		5.12	SQ	7.43
49	335	69	12.19		8.11	SQ	7.43
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	38.54		2.38	SQ	7.42
14	332	215	13.37		7.70	SQ	7.43
15	333	79	15.83		6.62	SQ	7.43
16	334	42	17.89		5.67	SQ	7.43
17	335	55	8.90		11.77	SQ	7.43
18							
19	Dayton Hollow Hydro						
20	331	13	9.92		10.41	SQ	7.43
21	332	976	10.69		10.18	SQ	7.43
22	333	110	14.13		6.52	SQ	7.43
23	334	65	21.25		4.55	SQ	7.43
24	335	90	8.92		10.85	SQ	7.43
25							
26	Taplin Gorge Hydro						
27	331	2	73.93		0.91	SQ	7.42
28	332	277	16.26		6.18	SQ	7.43
29	333	1	81.51		0.79	SQ	7.41
30	334	17	22.08		3.97	SQ	7.43
31	335	66	11.71		8.59	SQ	7.43
32							
33	Bemidji Hydro						
34	331	116	13.15		7.78	SQ	7.43
35	332	491	13.11		8.20	SQ	7.43
36	333	138	19.56		5.76	SQ	7.43
37	334	2	72.90		5.76	SQ	7.42
38	335	1	11.85		9.63	SQ	7.43
39							
40	HYDRO PROD	3,829					
41							
42	OTHER PRODUCTION						
43	Jamestown Peaking #1						
44	341	84	24.42	-1.40	3.35	SQ	9.38
45	342	207	16.46	-1.40	5.96	SQ	9.39
46	343	574	32.70	-1.40	2.29	SQ	9.38
47	345	45	46.75	-1.40	3.22	SQ	9.38
48	346	33	17.27	-1.40	5.54	SQ	9.39
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	53	29.08	-2.40	2.71	SQ	9.38
14	342	89	28.17	-2.40	3.13	SQ	9.38
15	343	422	39.06	-2.40	1.67	SQ	9.38
16	345	41	41.87	-2.40	1.45	SQ	9.38
17	346	2	38.91	-2.40	1.46	SQ	9.38
18							
19	Jamestown Peaking #2						
20	341	14	16.98	-1.40	6.04	SQ	9.39
21	342	7	27.65	-1.40	2.32	SQ	9.38
22	343	564	37.83	-1.40	1.74	SQ	9.38
23	345	34	15.32	-1.40	5.48	SQ	9.39
24	346	4	37.45	-1.40	4.55	SQ	9.38
25							
26	Fergus Falls Ctrl Ctr						
27	343	273	33.90		2.86	SQ	16.14
28							
29	Solway Combust Turbine						
30	341	2,978	33.36	-0.40	2.86	SQ	23.73
31	342	668	33.42	-0.40	2.82	SQ	23.73
32	343	14,469	33.45	-0.40	2.87	SQ	23.73
33	345	861	33.59	-0.40	2.83	SQ	23.73
34	346	227	32.06	-0.40	2.95	SQ	23.73
35							
36	Langdon Wind Energy						
37	341	1,798	24.27	-1.50	4.09	SQ	18.07
38	344	50,770	24.19	-1.50	4.15	SQ	18.07
39	345	5,465	23.62	-1.50	4.17	SQ	18.07
40	346	59	19.50	-1.50	5.08	SQ	18.07
41							
42	Ashtabula Wind Energy						
43	341	2,469	24.26	-1.20	4.06	SQ	19.02
44	344	82,256	24.19	-1.20	4.11	SQ	19.02
45	345	4,871	24.15	-1.20	4.08	SQ	19.02
46	346	26	20.45	-1.20	4.86	SQ	19.02
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	1,795	24.24	-2.00	4.07	SQ	19.97
14	344	52,401	24.19	-2.00	4.11	SQ	19.97
15	345	3,853	24.22	-2.00	4.07	SQ	19.97
16	346	70	21.40	-2.00	4.82	SQ	19.97
17							
18	OTHER PROD	227,482					
19							
20	TRANSMISSION PLANT						
21	350.1	7,167			1.43		70.00
22	353	61,103	65.14	-5.00	1.54	R1	52.96
23	354	41,583	70.00	-10.00	1.84	R5	55.88
24	355	54,565	70.36	-50.00	1.94	R2	53.85
25	356	55,348	70.26	-30.00	1.70	R2	53.33
26	358	7	41.40	-5.00	1.37	S4	10.33
27	SUBTOTAL	219,773					
28							
29	DISTRIBUTION PLANT						
30	362	53,917	40.64	5.00	2.09	SC	32.24
31	364	30,139	68.08	-75.00	2.47	R3	48.37
32	365	10,860	65.20	-100.00	2.78	R2.5	44.11
33	367	36,456	39.90	-5.00	2.34	R4	24.63
34	368	72,675	40.14	50.00	1.25	R2.5	28.20
35	369	-1,613	55.20	-150.00	4.16	S5	32.98
36	369.1	22,359	45.12	-20.00	2.59	R4	30.51
37	370	15,532	29.88		3.17	L0.5	20.69
38	370.1	2,991	12.03		9.66	R5	3.56
39	370.2	20	5.00		20.00	SQ - Amortized	1.97
40	371.2	3,280	23.21	10.00	3.85	L0	17.01
41	373	2,290	22.49	-5.00	3.34	L0.5	15.24
42	SUBTOTAL	248,906					
43							
44	GENERAL PLANT						
45	390	14,672	47.47	10.00	2.03	R1.5	31.71
46	390.1	3,285	35.13	51.50	0.37	SQ	16.14
47	390.2	441	37.14	38.60	0.77	SQ	11.32
48	390.3	2,048	50.54	93.80	-2.06	SQ	20.87
49	391	570	15.00		6.67	SQ - Amortized	5.74
50	391.1	375	10.00		10.00	SQ - Amortized	3.88

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	154	10.00		10.00	SQ - Amortized	2.17
14	391.5	1,986	5.00		20.00	SQ - Amortized	2.12
15	391.6	834	5.00		20.00	SQ - Amortized	2.19
16	392	15,156					
17	Aircraft	1,011	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	2,265	15.00		6.67	SQ - Amortized	9.25
29	394.2	304	15.00		6.67	SQ - Amortized	8.50
30	395		15.00		6.67	SQ - Amortized	
31	396	405	25.98	20.00	2.76	L0	17.03
32	397	568	15.00		6.67	SQ - Amortized	10.31
33	397.1	731	10.00		10.00	SQ - Amortized	5.69
34	397.2	2,420	15.00		6.67	SQ - Amortized	7.82
35	397.3	219	10.00		10.00	SQ - Amortized	5.94
36	397.4	1,061	40.24	5.00	2.00	R3	25.69
37	SUBTOTAL	48,505					
38							
39	TOTAL	872,897					
40							
41	SUBACCOUNTS USED						
42							
43							
44							
45							
46							
47							
48							
49							
50							

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) 12/31/2015	Year/Period of Report 2015/Q4
Otter Tail Power Company			
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.

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	365,817		365,817	
3					
4	SD Public Utilities Commission	60,703		60,703	
5					
6	ND Public Service Commission	-16,452		-16,452	
7					
8	Federal Energy Regulatory Commission	604,455		604,455	
9					
10	Other Expenses:				
11	MN Public Utilities Commission:				
12	E017/C-15-176 (Enbridge Donaldson)		66,862	66,862	
13	E017/GR-15-1033 (MN Rate Case)		290,748	290,748	
14	Miscellaneous		101,538	101,538	
15					
16	ND Public Service Commission:				
17	Miscellaneous		7,864	7,864	
18					
19	SD Public Utilities Commission:				
20	Miscellaneous		12,137	12,137	
21					
22	FERC				
23	ER14-2850/ER14-2851 (Integr IS Parties/SPP)		417,982	417,982	
24	ER16-209 SPP/CPEC (Formula Rate)		60,000	60,000	
25	ER16-584 (FRES ITA)		28,000	28,000	
26	Miscellaneous		193,899	193,899	
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	1,014,523	1,179,030	2,193,553	

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	365,817					2
							3
Electric	928	60,703					4
							5
Electric	928	-16,452					6
							7
Electric	928	604,455					8
							9
							10
							11
Electric	928	66,862					12
Electric	928	290,748	290,748			290,748	13
Electric	928	101,538					14
							15
							16
Electric	928	7,864					17
							18
							19
Electric	928	12,137					20
							21
							22
Electric	928	417,982					23
Electric	928	60,000					24
Electric	928	28,000					25
Electric	928	193,899					26
							27
							28
							29
							30
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							44
							45
		2,193,553	290,748			290,748	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		University of North Dakota
11		Microbeam Technologies
12		Chartwell Inc
13		E Source Companies Inc
14		
15		
16	Sub-Total Performed Externally	
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33	SUM OF ABOVE	
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
31,106		920	31,106		4
1,084		930.2	1,084		5
					6
32,190			32,190		7
					8
					9
	7,500	506	7,500		10
	10,500	506	10,500		11
	8,097	930.2	8,097		12
	15,126	930.2	15,126		13
					14
					15
	41,223		41,223		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
32,190	41,223		73,413		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)	69,043,799		69,043,799
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	13,658,840		13,658,840
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	13,658,840		13,658,840
72	Plant Removal (By Utility Departments)			
73	Electric Plant	3,877,476		3,877,476
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	3,877,476		3,877,476
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock (151)	56,546		56,546
79	Miscellaneous Deferred Debits (186)	1,303,872		1,303,872
80	Other Electric Revenue (456)	943,984		943,984
81	Expenses of Nonutility Operations (417.1)	150,921		150,921
82	Expenses for Certain Civic, Political and Related Activity (4	86,260		86,260
83	Other Deductions (426.5)	70,207		70,207
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	2,611,790		2,611,790
96	TOTAL SALARIES AND WAGES	89,191,905		89,191,905

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) 12/31/2015	Year/Period of Report 2015/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) 12/31/2015	Year/Period of Report End of <u>2015/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)  
12/31/2015

Year/Period of Report  
End of 2015/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					
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18					
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31					
32					
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34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch				8,154,013	\$/MW-Hr	738,566
2	Reactive Supply and Voltage				4,210,030	\$/MW-Hr	629,394
3	Regulation and Frequency Response	25,373	\$/MW-Hr	18,015			
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)	25,373		18,015	12,364,043		1,367,960

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) 12/31/2015	Year/Period of Report 2015/Q4
FOOTNOTE DATA			

**Schedule Page: 398 Line No.: 1 Column: d**

Scheduling, System Control and Dispatach does not include \$11,622 of services purchased from WAPA which were purchased with a "Unit of Measure" of \$/Schedule - Day.

Name of Respondent  
Otter Tail Power Company

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

Date of Report  
(Mo, Da, Yr)  
12/31/2015

Year/Period of Report  
End of 2015/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	897	5	12	896	1				
2	February	842	26	8	841	1				
3	March	805	4	8	804	1				
4	Total for Quarter 1				2,541	3				
5	April	647	7	11	646	1				
6	May	567	12	9	566	1				
7	June	683	25	16	682	1				
8	Total for Quarter 2				1,894	3				
9	July	683	27	15	682	1				
10	August	716	14	16	715	1				
11	September	717	3	17	716	1				
12	Total for Quarter 3				2,113	3				
13	October	631	29	9	630	1				
14	November	725	19	9	724	1				
15	December	842	28	9	841	1				
16	Total for Quarter 4				2,195	3				
17	Total Year to Date/Year				8,743	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) 12/31/2015	Year/Period of Report 2015/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:  
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(2)  A Resubmission

Date of Report  
(Mo, Da, Yr)  
12/31/2015

Year/Period of Report  
End of 2015/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)	4,593,604
3	Steam	1,794,785	23	Requirements Sales for Resale (See instruction 4, page 311.)	3,477
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	112,383
5	Hydro-Conventional	20,010	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	11,858
7	Other	491,173	27	Total Energy Losses	738,444
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	5,459,766
9	Net Generation (Enter Total of lines 3 through 8)	2,305,968			
10	Purchases	3,283,337			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	116,856			
17	Delivered	246,395			
18	Net Transmission for Other (Line 16 minus line 17)	-129,539			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	5,459,766			

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) 12/31/2015	Year/Period of Report End of <u>2015/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	573,379	9,408	897	5	1200
30	February	536,063	19,296	842	26	800
31	March	564,189	10,127	805	4	800
32	April	437,488	3,359	647	7	1100
33	May	415,136	3,566	567	12	900
34	June	437,537	1,618	683	25	1600
35	July	531,606	1,825	683	27	1500
36	August	406,813	11,336	716	14	1600
37	September	341,975	9,396	717	3	1700
38	October	364,041	9,974	631	29	900
39	November	378,920	17,509	725	19	900
40	December	472,620	14,969	842	28	900
41	TOTAL	5,459,767	112,383			

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) 12/31/2015	Year/Period of Report 2015/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 term 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)	151			256		
7	Plant Hours Connected to Load	8256			4562		
8	Net Continuous Plant Capability (Megawatts)	151			255		
9	When Not Limited by Condenser Water	151			255		
10	When Limited by Condenser Water	151			255		
11	Average Number of Employees	79			85		
12	Net Generation, Exclusive of Plant Use - KWh	662451134			836480578		
13	Cost of Plant: Land and Land Rights	713587			374603		
14	Structures and Improvements	33353489			84848400		
15	Equipment Costs	130052713			239766274		
16	Asset Retirement Costs	1377063			896678		
17	Total Cost	165496852			325885955		
18	Cost per KW of Installed Capacity (line 17/5) Including	1142.1453			1460.3897		
19	Production Expenses: Oper, Supv, & Engr	666178			640456		
20	Fuel	12850945			19402615		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	1500255			605753		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	595615			616907		
26	Misc Steam (or Nuclear) Power Expenses	1244332			2289516		
27	Rents	3108			61		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	302666			330388		
30	Maintenance of Structures	351819			573881		
31	Maintenance of Boiler (or reactor) Plant	1427416			3785162		
32	Maintenance of Electric Plant	182007			2815009		
33	Maintenance of Misc Steam (or Nuclear) Plant	452486			425659		
34	Total Production Expenses	19576827			31485407		
35	Expenses per Net KWh	0.0296			0.0376		
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	573148	3411	0	535958	3627	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	6974	140000	0	8222	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	21.546	75.222	0.000	37.113	74.840	0.000
41	Average Cost of Fuel per Unit Burned	21.554	92.400	0.000	36.451	87.700	0.000
42	Average Cost of Fuel Burned per Million BTU	1.545	15.714	0.000	2.217	14.915	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.019	0.000	0.000	0.023	0.000	0.000
44	Average BTU per KWh Net Generation	12106.000	0.000	0.000	10829.000	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)	43	0
7	Plant Hours Connected to Load	527	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	17660292	0
13	Cost of Plant: Land and Land Rights	89809	0
14	Structures and Improvements	4411779	0
15	Equipment Costs	24123622	0
16	Asset Retirement Costs	0	0
17	Total Cost	28625210	0
18	Cost per KW of Installed Capacity (line 17/5) Including	643.2631	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	753997	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	259642	0
26	Misc Steam (or Nuclear) Power Expenses	68488	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	9202	0
30	Maintenance of Structures	44538	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	515311	0
33	Maintenance of Misc Steam (or Nuclear) Plant	5307	0
34	Total Production Expenses	1656485	0
35	Expenses per Net KWh	0.0938	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	184681	380
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	156208	140000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.655	0.000
41	Average Cost of Fuel per Unit Burned	3.888	94.500
42	Average Cost of Fuel Burned per Million BTU	3.888	16.071
43	Average Cost of Fuel Burned per KWh Net Gen	0.043	0.000
44	Average BTU per KWh Net Generation	10584.000	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 term 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
	145			41			21		6
	7071			20			19		7
	141			43			20		8
	141			43			20		9
	141			43			20		10
	39			1			0		11
	295853600			79757			144917		12
	565967			24614			12339		13
	6132426			305657			229834		14
	60616704			7379221			3891658		15
	587343			0			0		16
	67902440			7709492			4133831		17
	528.4237			160.2472			171.5283		18
	308932			24190			8991		19
	9198656			19942			19949		20
	0			0			0		21
	1281925			0			0		22
	0			0			0		23
	0			0			0		24
	841772			69040			22716		25
	1041694			11428			2005		26
	0			0			0		27
	108771			0			0		28
	181290			36972			6041		29
	300754			7646			10712		30
	1382366			0			0		31
	66366			102475			39685		32
	627852			0			0		33
	15340378			271693			110099		34
	0.0519			3.4065			0.7597		35
Coal	Oil		Oil			Oil			36
Tons	Barrels		Barrels			Barrels			37
182353	1099	0	153	0	0	170	0	0	38
9200	140000	0	140000	0	0	140000	0	0	39
42.335	79.930	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
48.639	92.110	0.000	130.032	0.000	0.000	117.010	0.000	0.000	41
2.643	15.665	0.000	22.114	0.000	0.000	19.900	0.000	0.000	42
0.031	0.000	0.000	0.250	0.000	0.000	0.138	0.000	0.000	43
11387.000	0.000	0.000	11304.000	0.000	0.000	6917.000	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)  
12/31/2015

Year/Period of Report  
End of 2015/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

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Date of Report  
(Mo, Da, Yr)  
12/31/2015

Year/Period of Report  
End of 2015/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) 12/31/2015	Year/Period of Report 2015/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

Name of Respondent  
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Date of Report  
(Mo, Da, Yr)  
12/31/2015

Year/Period of Report  
End of 2015/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: <span style="float: right;">(c)</span>	0	FERC Licensed Project No. Plant Name: <span style="float: right;">(d)</span>	0	FERC Licensed Project No. Plant Name: <span style="float: right;">(e)</span>	0	Line No.
						1
						2
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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	4,951	661,464
3	Wright	1922	0.40	0.5	1,623	1,776,422
4	Pisgah	1917	0.52	0.7	4,544	712,212
5	Dayton Hollow	1909	0.97	1.0	5,026	1,864,753
6	Taplin Gorge	1925	0.56	0.5	3,866	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	1.4		
12						
13	Wind Turbine Plants					
14	Langdon	2007	40.50	40.4	147,666	79,236,179
15	Ashtabula	2008	48.00	48.2	150,954	116,527,862
16	Luverne	2009	49.50	49.9	174,646	72,784,083
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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
827,865	13,598		21,791	-		2
3,662,726	9,414		81,573	-		3
965,056	8,042		46,477	-		4
1,779,345	8,490		51,289	-		5
1,799,379	8,049		33,192	-		6
	26,809		24,863	-		7
						8
						9
281,197	1,671		7,012	Oil		10
				Oil		11
						12
						13
1,961,389	937,195					14
2,418,694	942,091		20,928			15
1,459,389	888,876		58,717			16
						17
						18
						19
						20
						21
						22
						23
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						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) 12/31/2015	Year/Period of Report 2015/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	Center	Maple River	345.00	345.00	Alum Tower	48.00		1
5	Chub Lake	Hampton	345.00	345.00	Steel Tower	18.00		1
6	Helena	Chub Lake	345.00	345.00	Steel Tower	21.00		1
7	Lyon County	Cedar Mountain	345.00	345.00	Steel Tower	50.00		2
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	414.00		
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		
3								
4								
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34								
35								
36					TOTAL	5,863.00		31

Name of Respondent  
Otter Tail Power Company

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

Date of Report  
(Mo, Da, Yr)  
12/31/2015

Year/Period of Report  
End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
	2,227,484	29,914,057	32,141,541					1
		1,133,893	1,133,893					2
	629,509	7,263,599	7,893,108					3
		5,458,744	5,458,744					4
	298,407	2,634,331	2,932,738					5
	456,889	2,601,070	3,057,959					6
	374,581	4,153,993	4,528,574					7
		2,030,683	2,030,683					8
		3,689,462	3,689,462					9
	616,601	8,864,861	9,481,462					10
	1,834,831	8,324,511	10,159,342					11
	2,373,675	24,116,045	26,489,720					12
								13
	6,339	2,022,422	2,028,761					14
	5,935	2,198,996	2,204,931					15
		1,272,077	1,272,077					16
		1,597,482	1,597,482					17
		4,722,361	4,722,361					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
		10,671,493	10,671,493					25
		4,433,129	4,433,129					26
		3,485,361	3,485,361					27
	489,732	4,363,737	4,853,469					28
	567,058	10,910,674	11,477,732					29
		715,936	715,936					30
								31
	74,783	9,444,657	9,519,440					32
	393,467	28,207,579	28,601,046					33
	14,354	192,183	206,537					34
		6,441,477	6,441,477					35
	10,368,598	295,396,422	305,765,020	5,955,479	1,629,890	37,889	7,623,258	36

Name of Respondent  
Otter Tail Power Company

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

Date of Report  
(Mo, Da, Yr)  
12/31/2015

Year/Period of Report  
End of 2015/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)	
	4,953	97,917,345	97,922,298					1
		72,673	72,673					2
				5,955,479	1,629,890	37,889	7,623,258	3
								4
								5
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								35
	10,368,598	295,396,422	305,765,020	5,955,479	1,629,890	37,889	7,623,258	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) 12/31/2015	Year/Period of Report 2015/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	Perham SE Tap SW1479	Perham SE Sub	0.50	Single Pole	20.00	1	1
2	North Oakes Jct 651	Oakes 812	8.40	Single Pole	19.60	1	1
3	Alexandria	MN Border	100.70	Single Tower	6.00	1	2
4	MN Border	Bison	34.90	Single Tower	6.00	1	2
5	Lyon County	MN Border	49.00	Single Tower	6.00	1	2
6	MN Border	Brookings	10.30	Single Tower	6.00	1	2
7	Lyon County	Hazel Creek	24.50	Single Tower	6.00	1	2
8	Hazel Creek	MN Valley	5.00	Single Tower	6.00	1	2
9							
10	Max Sub	Max, ND	0.10	Single Pole	19.50	1	1
11							
12							
13							
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43							
44	TOTAL		233.40		95.10	9	15

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)	
1/0RT2	ACSR	3651P	115		410,581	76,072		486,653	1
266 Waxw	ACSR-T2	Delta-T2	41	221,831	1,283,431	720,725		2,225,987	2
954	ACSS	Delta	345	2,227,484	27,311,534	2,602,523		32,141,541	3
954	ACSS	Delta	345	616,601	8,093,618	771,243		9,481,462	4
954	ACSS	Delta	345		566,946	566,946		1,133,892	5
954	ACSS	Delta	345		1,846,481	1,842,981		3,689,462	6
954	ACSS	Delta	345		1,015,342	1,015,342		2,030,684	7
954	ACSS	Delta	230		357,968	357,968		715,936	8
									9
266	ACSR	Vertical3102	41		9,752	20,233	3,959	33,944	10
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				3,065,916	40,895,653	7,974,033	3,959	51,939,561	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	Transmission	230.00	115.00	13.80
4	Big Stone, SD Highway 12 - 63215	Transmission	115.00	41.60	
5	Browns Valley, MN - 230 kv (Peever) - 63325	Transmission	230.00	41.60	
6	Buffalo, ND - 345 kv - 63258	Transmission	345.00	115.00	43.00
7	Canby, MN - 115 kv - 63211	Transmission	115.00	41.60	
8	Cass Lake, MN - 230 kv - 620447	Transmission	230.00	115.00	13.80
9	Cass Lake, MN - 115 kv - 63347	Transmission	115.00	69.00	41.60
10	Clearbrook, MN - 115 kv - 63241	Transmission	115.00	41.60	
11	Crookston, MN - 115 kv - 63249	Transmission	115.00	41.60	
12	Devils Lake, ND - East 115 kv - 63265	Transmission	115.00	41.60	
13	Devils Lake, ND - SW 115 kv - 224	Transmission	115.00	41.60	
14	Donaldson, MN - 115 kv - 63255	Transmission	115.00	41.60	
15	Fergus Falls, MN - Hoot Lake 115 kv - 63223	Transmission	115.00	43.80	
16	Fertile, MN - 115 kv - 63250	Transmission	115.00	41.60	
17	Finley, ND - Pickert 115 kv - 711	Transmission	230.00	72.00	41.60
18	Forman, ND - Forman 230 kv - 63363	Transmission	230.00	115.00	41.60
19	Hensel, ND - 115 kv - 63157	Transmission	115.00	72.00	43.80
20	Hetland, SD - 115 kv - 63209	Transmission	115.00	41.60	
21	Jamestown, ND - 345 kv - 63369	Transmission	345.00	115.00	43.00
22	Jamestown, ND - Peaking Plant 115 kv - 63272	Transmission	115.00	41.60	
23	Maple River, ND - 345 kv - 66792	Transmission	345.00	230.00	13.80
24	Mapleton, ND - 115 kv - 63203	Transmission	115.00	41.60	
25	Marietta, MN - 115 kv - 63213	Transmission	115.00	41.60	
26	Northwoods, MN - 115kv - 63282	Transmission	115.00	41.60	
27	Oakes, ND - 230 kv - 63362	Transmission	230.00	41.60	
28	Ortonville, MN - 115 kv - 63216	Transmission	115.00	41.60	
29	Pelican Rapids, MN - 115 k - 63234	Transmission	115.00	41.60	
30	Plummer, MN - 115kv - 7967	Transmission	115.00	41.60	
31	Rugby, ND - 230 kv - 63373	Transmission	230.00	115.00	13.80
32	Rugby, ND - 230 kv - 63373	Transmission	230.00	115.00	41.60
33	Spiritwood, ND	Transmission	115.00	41.60	
34	Toronto, SD - 115 kv - 63210	Transmission	115.00	41.60	
35	Wahpeton Inventory (came from Cass Lake )	Transmission	115.00	69.00	41.60
36	WAPA Summit, ND	Transmission	115.00	41.60	
37	Wilton, MN 230 kV - 63345	Transmission	230.00	115.00	13.80
38	Winger, MN 63238	Transmission	230.00	115.00	13.20
39	Subtotal:		6095.00	2533.40	433.20
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	Transmission Subs Under 10,000 kva				
2	Colgate	Transmission	69.00	43.80	12.50
3	Green Valley	Transmission	67.00	41.60	
4	Lake Preston	Transmission	69.00	44.00	
5	St Vincent	Transmission	69.00	41.60	
6	Wahpeton Inventory	Transmission	69.00	41.60	
7	Total:		6438.00	2746.00	445.70
8					
9	Distribution Subs 10,000 kva or higher				
10	Bemidji, MN 25th Street	Distribution	69.00	12.50	
11	Bemidji, MN Airport	Distribution	41.60	12.50	
12	Bemidji, MN Nymore	Distribution	69.00	12.50	
13	Bemidji, MN Industrial Park	Distribution	69.00	12.50	
14	Bottineau, ND Downtown - Not In Service	Distribution	41.60	12.50	
15	Casselton, ND	Distribution	41.60	12.50	
16	Casselton, ND Ethonal plant	Distribution	115.00	12.50	
17	Clearbrook, MN Pipeline	Distribution	115.00	4.16	
18	Cooperstown, ND	Distribution	41.60	12.50	
19	Crookston, MN Parkview	Distribution	41.60	12.50	
20	Crookston, MN South Main	Distribution	41.60	12.50	
21	Dawson, Mn Dawson Mills	Distribution	115.00	12.50	
22	Devils Lake, ND Downtown	Distribution	41.60	4.16	
23	Enderlin, ND	Distribution	115.00	12.50	
24	Fairmount, ND	Distribution	115.00	12.50	
25	Fergus Falls, MN Edgetown	Distribution	115.00	12.50	
26	Fergus Falls, MN Hoot Lake	Distribution	115.00	12.50	
27	Fergus Falls, MN South East	Distribution	115.00	12.50	
28	Gwinner, ND	Distribution	115.00	12.50	
29	Harvey, ND Northwest	Distribution	115.00	12.50	
30	Itasca, MN Minnesota Pipeline	Distribution	115.00	4.16	
31	Jamestown, ND Downtown	Distribution	115.00	12.50	
32	Jamestown, ND North	Distribution	115.00	12.50	
33	Jamestown, ND Potato	Distribution	115.00	12.50	
34	Jamestown, ND Southwest	Distribution	41.60	12.50	
35	Lake Norden, SD Dairy	Distribution	41.60	12.50	
36	Lisbon, ND Town	Distribution	115.00	12.50	
37	Mahnomen, MN	Distribution	115.00	12.50	
38	Milbank, SD Northwest	Distribution	41.60	12.50	
39	Milbank, SD South	Distribution	41.60	12.50	
40	Morris, MN Northeast	Distribution	41.60	12.50	

**SUBSTATIONS**

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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 South	Distribution	115.00	12.50	
2	Oakes, ND North	Distribution	41.60	12.50	
3	Parkers Prairie	Distribution	41.60	12.50	
4	Pelican Rapids, MN Turkey Plant	Distribution	115.00	12.50	
5	Perham, MN	Distribution	115.00	12.50	
6	Rosholt, SD	Distribution	41.60	12.50	
7	Rugby, ND South	Distribution	41.60	12.50	
8	Spiritwood, ND	Distribution	115.00	12.50	
9	Wahpeton Inventory	Distribution	115.00	12.50	
10	Wahpeton Inventory	Distribution	115.00	4.16	
11	Wahpeton Inventory	Distribution	41.60	12.50	
12	Wahpeton Inventory	Distribution	41.60	4.16	
13	Wahpeton, ND North 115 kv - 63230	Distribution	115.00	12.50	
14	Wahpeton, ND Northwest	Distribution	41.60	12.50	
15	Wheaton, MN South	Distribution	115.00	12.50	
16	Distribution Subtotal:		3757.40	533.30	
17					
18	Distribution Under 10,000 kva	Distribution			
19	Distribution Total		3757.40	533.30	
20	Transmission From Above		6438.00	2746.00	445.70
21	Transmission & Distribution		10195.40	3279.30	445.70
22					
23					
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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
26	1					5
112	1					6
27	1					7
187	1					8
40	1					9
13	1					10
95	2					11
34	1					12
57	1					13
20	2					14
30	1					15
10	1					16
60	1					17
140	1					18
55	1					19
45	1					20
224	2					21
56	1					22
672	2					23
20	1					24
10	1					25
13	1					26
52	2					27
22	1					28
13	1					29
34	1					30
125	1					31
140	1					32
17	1					33
45	1					34
		1				35
25	1					36
140	1					37
140	1					38
2996	41	1				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
6	1					2
7	1					3
9	1					4
8	1					5
		1				6
3026	45	2				7
						8
						9
20	1					10
14	1					11
14	1					12
11	1					13
10	3					14
10	1					15
94	2					16
28	2					17
10	1					18
10	1					19
39	2					20
10	1					21
10	1					22
14	1					23
10	3					24
37	1					25
37	1					26
37	1					27
20	2					28
14	1					29
11	1					30
14	1					31
14	1					32
14	1					33
14	1					34
12	1					35
14	1					36
14	1					37
25	1					38
22	1					39
12	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	3					1
10	3					2
10	1					3
10	1					4
28	2					5
10	1					6
10	1					7
84	2					8
		1				9
		1				10
		4				11
		1				12
24	2					13
20	2					14
12	1					15
845	58	7				16
						17
						18
845	58	7				19
3026	45	2				20
3871	103	9				21
						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) 12/31/2015	Year/Period of Report 2015/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	<b>Non-power Goods or Services Provided by Affiliated</b>			
2	Construction work in progress	Otter Tail Corporation	107	246,221
3	Civic and political activities	Otter Tail Corporation	186	1,488
4	Expenditures for certain civic, political and	Otter Tail Corporation	426.4	13,071
5	Dividends declared - common stock	Otter Tail Corporation	438	36,950,717
6	Corporate allocated A&G expense	Otter Tail Corporation	See Note	11,678,686
7				
8	Construction work in progress	BTD Manufacturing	143	-2,081
9	Steam power generation - maintenance of structures	BTD Manufacturing	241	-426
10	Distribution expense - mtce of overhead lines	BTD Manufacturing	593	750
11	Printing, design and mailing services	BTD Manufacturing	417	-6,443
12				
13				
14				
15				
16				
17				
18				
19				
20	<b>Non-power Goods or Services Provided for Affiliate</b>			
21	Printing, design & mailing services	Otter Tail Corporation	417	80,402
22	Other deductions	Otter Tail Corporation	426.5	603,906
23				
24	Printing, design & mailing services	BTD Manufacturing	417	6,443
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	<b>Non-power Goods or Services Provided by Affiliated</b>			
2				

Name of Respondent

Otter Tail Power Company

This Report Is:

(1)  An Original

(2)  A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2015

Year/Period of Report

End of 2015/Q4

**TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES**

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	<b>Non-power Goods or Services Provided for Affiliate</b>			
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	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2015	Year/Period of Report 2015/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

**Schedule Page: 429 Line No.: 6 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.: 6 Column: c**

The following accounts were charged:

500	\$	19,693
506		13,552
560		1,436
908		8,421
912		1,350
920		5,024,167
921		3,819,328
923		1,006,942
924		5,190
925		167,308
926		64,136
928		8,460
930.1		17,212
930.2		961,236
931		188,997
935		371,258
		-----
Total	\$	11,678,686

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