

THIS FILING IS

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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)



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 2013/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 18th of the following year (18 CFR § 141.1), and
- b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

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

GENERAL INSTRUCTIONS

- I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.
- II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.
- III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.
- IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.
- V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).
- VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.
- VII. For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.
- VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.
- IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

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

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

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

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

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

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

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

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

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

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

**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>2013/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> 12/31/2013

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> 04/08/2014
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	

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) 12/31/2013	Year/Period of Report End of <u>2013/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> 12/31/2013	Year/Period of Report End of <u>2013/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	President and Chief Executive Officer, Utility	Charles S. MacFarlane	935,037
2			
3	Vice President, IT and Special Projects	Rodney C.H. Scheel	239,503
4			
5	Vice President, Customer Service	Mark H. Helland	241,208
6			
7	Vice President, Administration	Thomas R. Brause	284,946
8			
9	Chief Financial Officer	George D. Bell	247,624
10			
11	Vice President, Energy Supply	Jan P. Rudolf	225,071
12			
13	Vice President, Asset Management	Timothy J. Rogelstad	213,580
14			
15	Treasurer * **	Kevin G. Moug	747,568
16			
17	General Counsel & Secretary [1]	Jennifer O. Smestad	246,440
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19	Assistant Treasurer * ** [2]	Brian Carlson	182,872
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37	[1] Effective 03/01/2013.		
38	[2] Effective 09/30/2013.		
39			
40	* This individual is an employee of		
41	Otter Tail Corporation.		
42			
43	** Only a portion of this individual's salary is		
44	allocated to respondent.		

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	Fargo, North Dakota
3		
4	George A. Koeck, Director, Assistant Secretary	Fargo, North Dakota
5		
6	Charles S. MacFarlane, Director, President and CEO, Utility	Fergus Falls, Minnesota
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8	Kevin Moug, Director, Treasurer	Fargo, North Dakota
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10	Shane Waslaski, Director	Fargo, North Dakota
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> No
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1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	MISO FERC Electric Tariff Original Vol. No. 1	ER98-1438-000
2	MISO FERC Electric Tariff 2nd Revised Vol. No. 1	ER04-895-000
3	MISO FERC Electric Tariff 2nd Revised Vol. No. 1	ER05-122-000
4	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER04-458-008
5	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER06-18-000
6	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER06-159-000
7	MISO FERC Electric Tariff 3rd Revised Vol. No. 1	ER09-91-000
8	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER09-1657-000
9	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER09-1779-000
10	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-183
11	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-686
12	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-1791
13	MISO FERC Electric Tariff 4th Revised Vol. No. 1	ER10-1492
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	ER11-3704
17	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER11-3279-000
18	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-297
19	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-312
20	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-334
21	MISO FERC Electric Tariff 5th Revised Vol. No. 1	ER12-450
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
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;001
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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)
12/31/2013

Year/Period of Report
End of 2013/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					
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10					
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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
1	NA	See specific footnote accompanying each applicable		NA
2		Form 1 Schedule		
3				
4				
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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 12/31/2013	Year/Period of Report End of <u>2013/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) 12/31/2013	Year/Period of Report 2013/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-13-378 dated June 20, 2013.
7. None.
8. The average annual increase for full-time nonunion employees was 2.99% effective April 1, 2013. Wages for Local Union 1570 were increased by 3.0% effective September 1, 2013. Wages for Local Unions 203, 239, 524, and 949 were increased by 3.0% effective November 1, 2013.
9. None.
10. Otter Tail Power Company is a subsidiary of Otter Tail Corporation.
11. (Reserved.)
12. None.
13. On March 1, 2013 Jennifer O. Smestad was named General Counsel and Secretary for the Company, replacing George A. Koeck, who remains General Counsel and Secretary for Otter Tail Corporation. On September 30, 2013 Brian Carlson was elected Assistant Treasurer of the Corporation, replacing Suzanne Allen.
14. Not applicable.

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	1,460,884,231	1,423,302,739
3	Construction Work in Progress (107)	200-201	184,779,895	75,758,114
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,645,664,126	1,499,060,853
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	626,272,583	592,427,672
6	Net Utility Plant (Enter Total of line 4 less 5)		1,019,391,543	906,633,181
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)		1,019,391,543	906,633,181
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		250,911	516,451
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)		238,419	272,895
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		1,670,542	1,321,064
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		2,159,872	2,110,410
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		10,300	9,600
36	Special Deposits (132-134)		3,508,580	3,544,456
37	Working Fund (135)		19,055	19,055
38	Temporary Cash Investments (136)		0	12,304,382
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		20,298,320	18,604,824
41	Other Accounts Receivable (143)		9,197,337	6,498,327
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		888,740	880,577
43	Notes Receivable from Associated Companies (145)		0	1,408
44	Accounts Receivable from Assoc. Companies (146)		11,132	171,501
45	Fuel Stock (151)	227	9,036,445	11,011,796
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	17,673,569	16,967,307
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

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)		398,997	376,629
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)		18,685,179	17,275,878
62	Miscellaneous Current and Accrued Assets (174)		90,919	76,922
63	Derivative Instrument Assets (175)		337,791	501,974
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		62,363	136,338
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		78,441,247	86,619,820
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		2,798,777	3,584,585
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	5,843,886	3,862,580
72	Other Regulatory Assets (182.3)	232	92,474,648	152,408,690
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)		147,263	22,694
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	165,165	168,706
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)		2,592,053	2,246,564
82	Accumulated Deferred Income Taxes (190)	234	108,426,748	115,976,211
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		212,448,540	278,270,030
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,312,441,202	1,273,633,441

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) 12/31/2013	2013/Q4
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 in rate-making purposes, illustrated as follows for the current year.

December 31, 2012	376,629
January 31, 2013	1,439,849
February 28, 2013	1,219,547
March 31, 2013	1,026,137
April 30, 2013	875,670
May 31, 2013	2,110,940
June 30, 2013	1,835,329
July 31, 2013	1,589,853
August 31, 2013	1,312,287
September 30, 2013	1,138,834
October 31, 2013	912,430
November 30, 2013	655,697
December 31, 2013	398,997
13-month average for rate-making	1,145,554

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	252,261,391	229,861,391
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	138,838,672	135,107,683
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)	-1,160,288	-1,627,095
16	Total Proprietary Capital (lines 2 through 15)		389,940,275	363,342,479
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	335,900,000	320,135,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	15,500,000
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)		335,900,000	335,635,000
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		577,000	577,000
29	Accumulated Provision for Pensions and Benefits (228.3)		103,108,963	160,950,162
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)		5,660,557	5,206,496
35	Total Other Noncurrent Liabilities (lines 26 through 34)		109,346,520	166,733,658
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		51,194,606	0
38	Accounts Payable (232)		68,930,607	47,153,222
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		1,360,978	1,201,276
41	Customer Deposits (235)		1,089,390	997,805
42	Taxes Accrued (236)	262-263	10,855,486	10,986,963
43	Interest Accrued (237)		4,253,960	4,588,505
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)		1,167,940	1,177,800
48	Miscellaneous Current and Accrued Liabilities (242)		160,312	158,403
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		11,781,900	18,233,970
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)		150,795,179	84,497,944
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	28,287,822	31,299,404
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	717,914	466,174
60	Other Regulatory Liabilities (254)	278	3,667,264	3,433,461
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		277,957,963	273,887,732
64	Accum. Deferred Income Taxes-Other (283)		15,828,265	14,337,589
65	Total Deferred Credits (lines 56 through 64)		326,459,228	323,424,360
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,312,441,202	1,273,633,441

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	364,701,808	342,731,195		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	223,802,793	204,599,030		
5	Maintenance Expenses (402)	320-323	27,414,190	26,276,567		
6	Depreciation Expense (403)	336-337	40,695,885	39,722,146		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	54,645	56,309		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	810,698	766,499		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	48,941	48,941		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		2,187,739	2,189,959		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		334,300	775,895		
13	(Less) Regulatory Credits (407.4)		514,284	480,913		
14	Taxes Other Than Income Taxes (408.1)	262-263	11,305,254	10,714,162		
15	Income Taxes - Federal (409.1)	262-263	-1,331,495	-3,080,962		
16	- Other (409.1)	262-263	-266,006	-356,449		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	31,916,567	32,664,385		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	21,939,569	22,785,018		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,925,310	-2,091,006		
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)		66	163		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		454,062	419,028		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		313,048,344	289,438,410		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		51,653,464	53,292,785		

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)	
364,701,808	342,731,195					2
						3
223,802,793	204,599,030					4
27,414,190	26,276,567					5
40,695,885	39,722,146					6
54,645	56,309					7
810,698	766,499					8
48,941	48,941					9
2,187,739	2,189,959					10
						11
334,300	775,895					12
514,284	480,913					13
11,305,254	10,714,162					14
-1,331,495	-3,080,962					15
-266,006	-356,449					16
31,916,567	32,664,385					17
21,939,569	22,785,018					18
-1,925,310	-2,091,006					19
						20
						21
66	163					22
						23
454,062	419,028					24
313,048,344	289,438,410					25
51,653,464	53,292,785					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)		51,653,464	53,292,785		
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)		984,638	2,034,337		
34	(Less) Expenses of Nonutility Operations (417.1)		613,122	1,699,849		
35	Nonoperating Rental Income (418)		54,945	41,858		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		257,848	296,037		
38	Allowance for Other Funds Used During Construction (419.1)		1,822,917	1,167,824		
39	Miscellaneous Nonoperating Income (421)		8,986,820	13,396,103		
40	Gain on Disposition of Property (421.1)		8,196	5,949		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		11,502,242	15,242,259		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		24,557	5,422		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		526,442	375,075		
46	Life Insurance (426.2)					
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		239,895	191,702		
49	Other Deductions (426.5)		3,837,633	8,538,555		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		4,628,527	9,110,754		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	5,880	5,392		
53	Income Taxes-Federal (409.2)	262-263	1,477,089	2,032,836		
54	Income Taxes-Other (409.2)	262-263	266,012	374,823		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	2,010,918	815,849		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	929,888	612,190		
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)		2,830,011	2,616,710		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		4,043,704	3,514,795		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		17,199,173	18,514,348		
63	Amort. of Debt Disc. and Expense (428)		387,011	430,852		
64	Amortization of Loss on Reaquired Debt (428.1)		337,182	279,960		
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)		539,699	-234,487		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,002,253	656,067		
70	Net Interest Charges (Total of lines 62 thru 69)		17,460,812	18,334,606		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		38,236,356	38,472,974		
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)		38,236,356	38,472,974		

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		134,730,951	130,734,936
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)		38,236,356	38,472,974
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess hydro licensing amortization		-61,467	(62,252)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-61,467	(62,252)
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			-34,505,367	(34,414,707)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-34,505,367	(34,414,707)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		138,400,473	134,730,951
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39	Amortization reserve, federal (Account 215.1)		438,199	376,732
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)		438,199	376,732
	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)		438,199	376,732
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		138,838,672	135,107,683
	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)	38,236,356	38,472,974
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	40,750,531	39,778,457
5	Amortization	1,246,649	1,246,291
6	Vehicle depreciation allocated to various operating accounts	1,575,392	
7			
8	Deferred Income Taxes (Net)	13,110,370	9,905,080
9	Investment Tax Credit Adjustment (Net)	-3,011,582	-1,882,345
10	Net (Increase) Decrease in Receivables	-958,566	616,178
11	Net (Increase) Decrease in Inventory	1,269,089	-543,512
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-688,360	5,715,009
14	Net (Increase) Decrease in Other Regulatory Assets	62,703,996	-11,312,406
15	Net Increase (Decrease) in Other Regulatory Liabilities	233,803	-247,166
16	(Less) Allowance for Other Funds Used During Construction	1,822,917	1,167,824
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other: (Increase) decrease in noncurrent assets and deferred debits	-98,848	140,233
19	Other: Increase (decrease) in noncurrent liab. and deferred credits	-56,668,591	17,830,856
20	Other: (Increase) decrease in other current assets	-1,207,508	3,584,812
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	94,669,814	102,136,637
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-160,695,183	-90,507,125
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	265,540	-86,271
30	(Less) Allowance for Other Funds Used During Construction	-1,822,917	-1,167,824
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-158,606,726	-89,425,572
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	-3,264,000	
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	12,634,000	
53	Other: (Increase) decrease in funds on deposit with trustee	35,876	-212,181
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-149,200,850	-89,637,753
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	40,900,000	
62	Preferred Stock		
63	Common Stock		
64	Other: Debt issuance expense	-283,874	-196,449
65			
66	Net Increase in Short-Term Debt (c)	51,194,606	
67	Other: Change in checks written in excess of cash	3,156,989	
68	Other: Proceeds from capital infusions	22,400,000	20,000,000
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	117,367,721	19,803,551
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-40,635,000	-60,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-34,505,367	-34,414,707
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	42,227,354	-14,671,156
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-12,303,682	-2,172,272
87			
88	Cash and Cash Equivalents at Beginning of Period	12,333,037	14,505,309
89			
90	Cash and Cash Equivalents at End of period	29,355	12,333,037

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) 12/31/2013	Year/Period of Report 2013/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 instrument 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 12/31/2013	Year/Period of Report End of <u>2013/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) 12/31/2013	Year/Period of Report 2013/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.

Reconciliation	<u>2013</u>		<u>2012</u>
Cash Equivalents	\$	0	\$ 12,304,382
Reconciliation	<u>2013</u>		<u>2012</u>
Cash - Account 131 (Line 35, Page 110)	\$	10,300	\$ 9,600
Working Fund - Account 135 (Line 37, Page 110)		19,055	19,055
Cash Equivalent - Account 136 (Above)		<u>0</u>	<u>12,304,382</u>
	\$	29,355	\$ 12,333,037

Otter Tail Power Company
Notes to Financial Statements
For the years ended December 31, 2013 and 2012

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 electric and nonelectric 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 an active wholesale participant in the Midcontinent Independent Transmission System Operator (MISO) markets.

OTP provides electricity to more than 130,000 customers in a service area with outer boundaries that encompass a total expanse of 70,000 square miles of western Minnesota, eastern North Dakota, and northeastern South Dakota. The territory served by OTP is predominantly agricultural. The aggregate population of OTP's retail electric service area is approximately 230,000. In this service area of 422 communities and adjacent rural areas and farms, approximately 125,646 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, 2013, OTP served 130,188 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>	2013	2012
Accounts Receivable	\$ 11	\$ 171
Accounts Payable	1,571	1,308
Long-Term Debt	--	15,500
Operating Revenues	70	86
Other Operation and Maintenance Expenses	8,083	6,048
Interest Expense	427	1,103

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The related party transactions predominately relate to electric sales to operating subsidiaries of Otter Tail Corporation and to the allocation of corporate overhead expenses and corporate aircraft usage to OTP. 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.

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 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 \$1,002,000 in 2013 and \$656,000 in 2012. 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 when incurred. 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 2.96% in 2013 and 2.98% in 2012. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Jointly Owned Facilities

The balance sheets include OTP's ownership interests in the assets and liabilities of Big Stone Plant (53.9%) and Coyote Station (35.0%). The following amounts are included in the December 31, 2013 and 2012 balance sheets:

<i>(in thousands)</i>	2013	2012
Big Stone Plant:		
Electric Plant in Service	\$ 142,780	\$ 141,221
Construction Work in Progress	94,913	22,335
Accumulated Depreciation	(83,005)	(80,588)
Net Plant	\$ 154,688	\$ 82,968
Coyote Station:		
Electric Plant in Service	\$ 162,095	\$ 160,617
Construction Work in Progress	303	578
Accumulated Depreciation	(96,907)	(93,564)
Net Plant	\$ 65,491	\$ 67,631

OTP is a joint owner, with other regional utilities, in certain transmission lines with the following ownership interests: 14.8% in the Bemidji-Grand Rapids 230 kV line, 13.3% in the Fargo-Monticello 345 kV line, 4.9% in the Brookings-Southeast Twin Cities Multi-Value Project (MVP) 345 kV line, 50.0% in the Big Stone South to Brookings MVP 345 kV line and 49.2% in the Big Stone South to Ellendale MVP 345 kV line. The following amounts for the jointly-owned transmission facilities are included in OTP's December 31, 2013 and 2012 balance sheets:

<i>(in thousands)</i>	2013	2012
Electric Plant in Service	\$ 26,337	\$ 25,852
Construction Work in Progress	71,205	30,171
Accumulated Depreciation	(837)	(483)
Net Plant	\$ 96,705	\$ 55,540

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 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 lignite 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 the 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.

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 first delivery of coal to Coyote Station, scheduled for 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. OTP's 35% share of development period costs, development fees and capital charges incurred by CCMC through December 31, 2013 is \$10.2 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, 2013 could be as high as \$10.2 million.

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.

Income Taxes

Otter Tail Corporation and its subsidiaries, including OTP, file a consolidated U.S. federal income tax return and various state and foreign 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 OTP's accounting for uncertain tax positions.

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

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.

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 815, *Derivatives and Hedging*. 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. OTP's unrealized gains and losses on forward energy contracts that do not meet the

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

definition of capacity contracts are marked to market and reflected on a net basis in electric revenue on OTP's statement of income. Under ASC 815, OTP's forward energy contracts that do not meet the definition of a capacity contract and are subject to unplanned netting do not qualify for the normal purchase and sales exception from mark-to-market accounting. OTP is required to mark to market these forward energy contracts and recognize changes in the fair value of these contracts as components of income over the life of the contracts. See note 4 for further discussion.

Use of Estimates

OTP uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric revenues, accrued renewable resource, transmission and environmental cost recovery rider revenues, valuations of forward energy contracts and actuarially determined benefits costs and liabilities. As better information becomes available (or actual amounts are known), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash Equivalents

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

Investments

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

<i>(in thousands)</i>	2013	2012
Cost Method:		
Economic Development Loan Pools	\$ 219	\$ 255
Equity Method:		
Partnerships	19	18
Total Investments	\$ 238	\$ 273

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 hierarchical 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 table presents, for each of the fair value hierarchy levels, OTP's assets and liabilities that are measured at fair value on a recurring basis as of December 31:

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

2013 (in thousands)	Level 1	Level 2	Level 3
Assets:			
Current Assets - Other:			
Forward Energy Contracts	\$ --	\$ --	\$ 338
Forward Gasoline Purchase Contracts		62	
Total Assets	\$ --	\$ 62	\$ 338
Liabilities:			
Derivative Liabilities - Forward Energy			
Contracts	\$ --	\$ 103	\$ 11,679
Total Liabilities	\$ --	\$ 103	\$ 11,679
2012 (in thousands)			
	Level 1	Level 2	Level 3
Assets:			
Current Assets - Other:			
Forward Energy Contracts	\$ --	\$ 292	\$ 210
Forward Gasoline Purchase Contracts		136	
Total Assets	\$ --	\$ 428	\$ 210
Liabilities:			
Derivative Liabilities - Forward Energy			
Contracts	\$ --	\$ 242	\$ 17,992
Total Liabilities	\$ --	\$ 242	\$ 17,992

The valuation techniques and inputs used for the Level 2 fair value measurements in the table above are as follows:

Forward Energy Contracts - Prices used for the fair valuation of these forward purchases and sales of electricity, which have illiquid trading points, are indexed to a price at an active market.

Forward Gasoline Purchase Contracts - These 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, 2013 and December 31, 2012, are based on prices indexed to observable prices at an active trading hub. The Level 3 forward electric price inputs ranged from \$6.95 per megawatt-hour under the active trading hub price to \$3.11 per megawatt-hour over the active trading hub price. The weighted average price was \$34.00 per megawatt-hour.

In the table above, \$117,000 of the fair value of the Level 3 forward energy contracts in a derivative asset position and \$11,679,000 of the fair value of the Level 3 forward energy contracts in a derivative liability position as of December 31, 2013 are 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 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 and the net income impact of any future fair valuation adjustments of these contracts will be \$0. When energy is delivered under these contracts, they 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 will be reversed along with any offsetting regulatory liabilities or assets. Because of regulatory accounting treatment,

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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, 2013 and 2012.

The remaining \$221,000 of the fair value of the Level 3 forward energy contracts in a derivative asset position and \$103,000 of the fair value of the Level 2 forward energy contracts in a derivative liability position as of December 31, 2013 are related to financial contracts that will not be settled by physical delivery of electricity but will be settled financially by the counterparty to the contract paying or receiving the difference between the contract price and the market price at the hour of scheduled delivery. Although the related forward energy purchase and sales contracts are 100% offsetting in terms of volumes and delivery periods, the purchase contracts and offsetting sales contracts do not have the same delivery points. Therefore, the net derivative gain related to these contracts of \$118,000 as of December 31, 2013 is subject to change in subsequent reporting periods or on settlement. These contracts are scheduled for settlement in January and February of 2014. Any fluctuation in the factors used in the fair valuation of these contracts would not result in a significant change to the net fair value of the contracts.

The following table presents changes in Level 3 forward energy contract derivative asset and liability fair valuations for the twelve-month periods ended December 31, 2013 and 2012:

<i>(in thousands)</i>	2013	2012
Forward Energy Contracts - Fair Values Beginning of Period	\$ (17,782)	\$ --
Transfers into Level 3 from Level 2	--	(15,884)
Less: Amounts Reversed on Settlement of Contracts Entered into in Prior Periods	7,943	5,135
Changes in Fair Value of Contracts Entered into in Prior Periods	(640)	(4,001)
Cumulative Fair Value Adjustments of Contracts Entered into in Prior Years at End of Period	(10,479)	(14,750)
Net Decrease in Value of Open Contracts Entered into in Current Period	(862)	(3,032)
Forward Energy Contracts - Net Derivative Liability Fair Values End of Period	\$ (11,341)	\$ (17,782)

Inventories

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

Supplemental Disclosures of Cash Flow Information

<i>(in thousands)</i>	As of December, 31	
	2013	2012
Noncash Investing Activities:		
Accounts Payable Outstanding Related to Capital Additions ¹	\$ 22,205	\$ 9,571
Accounts Receivable Outstanding Related to Joint Plant Owner's Share of Capital Additions ²	\$ 3,264	\$ --

¹Amounts are included in cash used for capital expenditures in subsequent periods when payables are settled.

²Amounts are deducted from cash used for capital expenditures in subsequent periods when cash is received.

<i>(in thousands)</i>	2013	2012
Cash Paid During the Year for:		
Interest (net of amount capitalized)	\$ 17,140	\$ 17,960
Income Tax Payments	\$ --	\$ 61

New Accounting Standards

Accounting Standards Update (ASU) 2011-11 and 2013-01

In December 2011, the FASB issued ASU 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and*

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Liabilities (ASU 2011-11), which requires disclosures regarding netting arrangements in agreements underlying derivatives, certain financial instruments and related collateral amounts, and the extent to which an entity's financial statement presentation policies related to netting arrangements impact amounts recorded to the financial statements. In January 2013, the FASB issued ASU 2013-01, *Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities* (ASU 2013-01), to clarify which instruments and transactions are subject to the offsetting disclosure requirements established by ASU 2011-11. The amendments in ASU 2013-01 apply to derivatives accounted for in accordance with ASC 815 and clarify that only derivatives accounted for in accordance with ASC 815 are within the scope of the disclosure requirements. These disclosure requirements do not affect the presentation of amounts in the balance sheets. ASU 2013-01 is effective for fiscal years beginning on or after January 1, 2013, and interim periods within those annual periods.

OTP implemented the disclosure guidance January 1, 2013. While certain of OTP's offsetting derivative asset and liability positions related to forward energy contracts with the same counterparty are subject to legally enforceable netting arrangements, OTP does not present its derivative assets and liabilities subject to legally enforceable netting arrangements, or any related payables or receivables, on a net basis on the face of its balance sheet. OTP has added disclosures and a table in note 4 to the financial statements indicating the amounts of its derivative forward energy contracts presented at fair value in accordance with ASC 815 that are subject to legally enforceable netting arrangements.

ASU 2013-02

In February 2013, the FASB issued ASU 2013-02, *Comprehensive Income (Topic 220): Reporting of Amounts Reclassified out of Accumulated Other Comprehensive Income*, which requires entities to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, entities are required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under accounting principles generally accepted in the United States of America (U.S. GAAP) to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, entities are required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail on these amounts. This ASU is effective for reporting periods beginning after December 15, 2012. Additional information required by this update is included on the face of OTP's statement of comprehensive income for the period ending December 31, 2013. The amounts of accumulated other comprehensive losses associated with OTP's pension and other post-retirement benefit programs that are being amortized and recognized as operating expenses and the income statement line item affected by the expense are disclosed in note 9 to the financial statements.

2. Rate and Regulatory Matters

Minnesota

2010 General Rate Case—OTP filed a general rate case on April 2, 2010 requesting an 8.01% base rate increase as well as a 3.8% interim rate increase. On May 27, 2010, the Minnesota Public Utilities Commission (MPUC) issued an order accepting the filing, suspending rates, and approving the interim rate increase, as requested, to be effective with customer usage on and after June 1, 2010. The MPUC held a hearing to decide on the issues in the rate case on March 25, 2011 and issued a written order on April 25, 2011. The MPUC authorized a revenue increase of approximately \$5.0 million, or 3.76% in base rate revenues, excluding the effect of moving recovery of wind investments to base rates. The MPUC's written order included: (1) recovery of Big Stone II costs over five years, (2) moving recovery of wind farm assets from rider recovery to base rate recovery, (3) transfer of a portion of Minnesota Conservation Improvement Program (MNCIP) costs from rider recovery to base rate recovery, (4) transfer of the investment in two transmission lines from rider recovery to base rate recovery, and (5) changing the mechanism for providing customers with a credit for margins earned on asset-based wholesale sales of electricity from a credit to base rates to a credit to the Minnesota Fuel Clause Adjustment. Final rates went into effect October 1, 2011. The overall increase to customers was

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

approximately 1.6% compared to the authorized interim rate increase of 3.8%, which resulted in an interim rate refund to Minnesota retail electric customers of approximately \$3.9 million in the fourth quarter of 2011. Pursuant to the order, OTP's allowed rate of return on rate base increased from 8.33% to 8.61% and its allowed rate of return on equity increased from 10.43% to 10.74%. OTP's authorized rates of return are based on a capital structure of 48.28% long term debt and 51.72% common equity.

Renewable Energy Standards, Conservation, Renewable Resource Riders—Minnesota has a renewable energy standard which requires OTP to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 17% by 2016; 20% by 2020 and 25% by 2025. In addition, a new standard established by the 2013 legislature requires 1.5% of total electric sales to be supplied by solar energy by the year 2020. OTP is currently evaluating the new legislation and potential options for meeting that standard. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards. OTP has acquired renewable resources and expects to acquire additional renewable resources in order to maintain compliance with the Minnesota renewable energy standard. OTP's compliance with the Minnesota renewable energy standard will be measured through the Midwest Renewable Energy Tracking System.

Under the Next Generation Energy Act of 2007, an automatic adjustment mechanism was established to allow Minnesota electric utilities to recover investments and costs incurred to satisfy the requirements of the renewable energy standard. The MPUC is authorized to approve a rate schedule rider to enable utilities to recover the costs of qualifying renewable energy projects that supply renewable energy to Minnesota customers. Cost recovery for qualifying renewable energy projects can be authorized outside of a rate case proceeding, provided that such renewable projects have received previous MPUC approval. Renewable resource costs eligible for recovery may include return on investment, depreciation, operation and maintenance costs, taxes, renewable energy delivery costs and other related expenses.

The costs for three major wind farms previously approved by the MPUC for recovery through OTP's Minnesota Renewable Resource Adjustment (MNRRA) were moved to base rates as of October 1, 2011 under the MPUC's April 25, 2011 general rate case order with the exception of the remaining balance of the MNRRA regulatory asset. A request for an updated rate to be effective October 1, 2012 was initially filed on June 28, 2012, followed by a revised filing on July 25, 2012. Because the request to extend the period of the new rate for 18 months was still under review, a supplemental filing was submitted on February 15, 2013, requesting that the current rate be retained until a majority of the remaining costs were recovered and that the MNRRA rate be set to zero effective May 1, 2013. The MPUC approved the February 15, 2013 request on April 4, 2013 and authorized that any unrecovered balance be retained as a regulatory asset to be recovered in OTP's next general rate case. Effective May 1, 2013 the resource adjustment on OTP's Minnesota customers' bills no longer includes MNRRA costs.

Transmission Cost Recovery (TCR) Rider—In addition to the MNRRA rider, the Minnesota Public Utilities Act provides a similar 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 2013 legislature passed legislation that 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

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

adjustments filed pursuant to the rate schedule. OTP's initial request for approval of a TCR rider was granted by the MPUC on January 7, 2010, and became effective February 1, 2010.

OTP requested recovery of its transmission investments being recovered through its Minnesota TCR rider rate as part of its general rate case filed on April 2, 2010. In its April 25, 2011 general rate case order, the MPUC approved the transfer of transmission costs then being recovered through OTP's Minnesota TCR rider to recovery in base rates. Final rates went into effect on October 1, 2011. OTP continues to utilize the TCR rider cost recovery mechanism to recover the remaining balance of current transmission projects and to recover costs associated with new transmission projects determined eligible for TCR rider recovery by the MPUC.

OTP filed a request for an update to its Minnesota TCR rider on October 5, 2010. In this TCR rider update, the MPUC addressed how to handle utility investments in transmission facilities that qualify for regional cost allocation under the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff). MISO regional cost allocation allows OTP to recover some of the costs of its transmission investment from the other MISO utilities. On March 26, 2012 the MPUC approved the 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 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.

On May 24, 2012 OTP filed a petition with the MPUC to seek a determination of eligibility for the inclusion of twelve additional transmission related projects in subsequent Minnesota TCR rider filings. On February 20, 2013 the MPUC approved three of the additional projects as eligible for recovery through the TCR rider. OTP filed its annual update to the TCR rider on February 7, 2013 to include the three new projects as well as updated costs associated with existing projects. On January 30, 2014 the MPUC approved OTP's 2013 TCR rider update but disallowed recovery of capitalized internal labor costs and costs in excess of CON estimates in the TCR rider. These costs will be removed from OTP's Minnesota TCR rider effective as of the date of the MPUC order. OTP will be allowed to seek recovery of these costs in a future rate case. OTP had a regulatory liability of \$0.7 million as of December 31, 2013 for amounts billed to Minnesota customers that are subject to refund through the Minnesota TCR rider.

Environmental Cost Recovery (ECR) Rider—On January 14, 2011 OTP filed a petition asking the MPUC for Advance Determination of Prudence (ADP) for costs associated with the design, construction and operation of the Best-Available Retrofit Technology (BART) compliant air quality control system at Big Stone Plant attributable to serving OTP's Minnesota customers, and on December 20, 2011 the MPUC granted OTP's petition for ADP for the Big Stone Plant air quality control system (AQCS). The MPUC written order was issued on January 23, 2012. On May 24, 2013 legislation was enacted in Minnesota which allowed OTP to file an emission-reduction rider for recovery of the revenue requirements of the AQCS. The legislation authorizes the rider to allow a current return on investment (including Construction Work in Progress (CWIP)) at the level approved in OTP's most recent general rate case, unless a different return is determined by the MPUC to be in the public interest. On July 31, 2013 OTP filed for a Minnesota ECR rider with the MPUC for recovery of its Minnesota jurisdictional share of the revenue requirements of its investment in the AQCS under construction at Big Stone Plant. The ECR rider recoverable revenue requirements include a current return on the project's CWIP balance. The MPUC granted approval of OTP's Minnesota ECR rider on December 18, 2013 with an effective date of January 1, 2014. The rate will be updated in an annual filing with the MPUC until the costs are rolled into base rates at an undetermined future date.

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 Next Generation Energy Act of 2007, passed by the Minnesota legislature in May 2007, transitions from a conservation spending goal to a conservation energy savings goal.

The MNDOC may require a utility to make investments and expenditures in energy conservation improvements whenever

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 MNCIP through the use of an annual recovery mechanism approved by the MPUC.

On January 11, 2012 the MPUC approved recovery of \$3.5 million for 2010 MNCIP financial incentives. Beginning in January 2012, OTP's MNCIP Conservation Cost Recovery Adjustment increased from 3.0% to 3.8% for all Minnesota retail electric customers. On March 30, 2012 OTP recognized an additional \$0.4 million of incentive related to 2011 and submitted its annual 2011 financial incentive filing request for \$2.6 million. In December 2012, the MPUC approved the recovery of \$2.6 million in financial incentives for 2011 and also ordered a change in the MNCIP cost recovery methodology used by OTP from a percentage of a customer's bill to an amount per kilowatt-hour (kwh) consumed. On January 1, 2013 OTP's MNCIP surcharge decreased from 3.8% of the customer's bill to \$0.00142 per kwh, which equates to approximately 1.9% of a customer's bill. OTP recognized \$2.6 million of MNCIP financial incentives in 2012 and an additional \$0.1 million in 2013 relating to 2012 program results. 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. OTP recognized \$3.9 million in MNCIP financial incentives in 2013 related to the results of its conservation improvement programs in Minnesota in 2013.

OTP had a regulatory asset of \$8.9 million for allowable costs and financial incentives eligible for recovery through the MNCIP rider that had not been billed to Minnesota customers as of December 31, 2013. OTP's Minnesota conservation recoverable costs and incentives totaled \$9.3 million in 2013, \$7.8 million in 2012 and \$8.0 million in 2011.

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.

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. OTP's 2010 NDRRA was in place from September 1, 2010 through March 31, 2012 with a recovery of \$15.6 million. On March 21, 2012 the NDPSC approved an update to OTP's NDRRA effective April 1, 2012. The updated NDRRA recovered \$9.9 million over the period April 1, 2012 through March 31, 2013. On December 28, 2012 OTP submitted its 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 and, on July 10, 2013, the NDPSC approved the rate implemented on April 1, 2013. OTP submitted its annual update to the NDRRA on December 31, 2013 with a proposed April 1, 2014 effective date. OTP has a regulatory asset of \$0.5 million for amounts eligible for recovery through the NDRRA rider that had not been billed to North Dakota customers as of December 31, 2013.

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. On April 29, 2011 OTP filed a request for an initial North Dakota TCR rider with the NDPSC, which was approved on April 25, 2012 and effective May 1, 2012. On August 31, 2012 OTP filed its annual update to the North Dakota TCR rider rate to reflect updated cost information associated with projects currently in the rider, as well as proposing to include costs associated with ten additional projects for recovery within the rider. The NDPSC approved the annual update on December 12, 2012 with an effective date of January 1, 2013. On August 30, 2013 OTP filed its annual update to its North Dakota TCR rider rate, which was approved on December 30, 2013 and became effective January 1, 2014. OTP has a regulatory liability of \$0.2 million as of December 31, 2013 for amounts

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

billed to North Dakota customers that are subject to refund through the North Dakota TCR rider.

Environmental Cost Recovery Rider—On May 9, 2012 the NDPSC approved OTP’s application for an ADP related to the Big Stone Plant AQCS. On February 8, 2013 OTP filed a request with the NDPSC for an ECR rider to recover OTP’s North Dakota jurisdictional share of carrying costs 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. OTP had a regulatory asset of \$2.3 million for amounts eligible for recovery through the North Dakota ECR rider that had not been billed to North Dakota customers as of December 31, 2013. The ECR rider rate will be updated at least annually in a filing with the NDPSC until the project costs are rolled into base rates at an undetermined future date.

South Dakota

2010 General Rate Case—On April 21, 2011 the SDPUC issued a written order approving an overall final revenue increase of approximately \$643,000 (2.32%) and an overall rate of return on rate base of 8.50% for the interim rates and final rates for OTP in South Dakota. Final rates were effective with bills rendered on and after June 1, 2011.

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. OTP submitted a request for an initial South Dakota TCR rider to the SDPUC on November 5, 2010. The South Dakota TCR was approved by the SDPUC and implemented on December 1, 2011. On September 4, 2012 OTP filed its annual update to the South Dakota TCR rider. Updated rates, approved on April 23, 2013, went into effect on May 1, 2013. OTP filed its annual update to the South Dakota TCR rider on August 30, 2013 with a supplemental filing made in February 2014 with a proposed implementation date of March 1, 2014.

Environmental Cost Recovery Rider—On March 30, 2012 OTP requested approval from the SDPUC for an ECR rider to recover costs associated with the Big Stone Plant AQCS. On April 17, 2013 OTP filed a request to either suspend or withdraw this filing. The SDPUC approved withdrawing this filing on April 23, 2013. Instead of receiving rider recovery on the portion of AQCS construction costs assignable to OTP’s South Dakota customers while the project is under construction, OTP will accrue an Allowance for Funds Used During Construction (AFUDC) on these costs and request recovery of, and a return on, the accumulated costs, including AFUDC, in a future rate filing in South Dakota.

Federal

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.

Effective January 1, 2010 the FERC authorized OTP’s implementation of a forward looking formula transmission rate under the MISO Tariff. OTP was also authorized by the FERC to recover in its formula rate: (1) 100% of prudently incurred CWIP in rate base and (2) 100% of prudently incurred costs of transmission facilities that are cancelled or abandoned for reasons beyond OTP’s control (Abandoned Plant Recovery), as determined by the FERC subsequent to abandonment, specifically for three regional transmission CapX2020 projects in which OTP is invested.

On December 16, 2010 the FERC approved the cost allocation for a new classification of projects in MISO called Multi-Value Projects (MVP). 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. On June 7, 2013, in response to a challenge to the MVP cost allocation heard before the United States Court of Appeals, Seventh Circuit, the Court ruled in favor of MISO and MISO transmission owners, issuing an order affirming the FERC’s approval of the MVP cost

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

allocation. On October 7, 2013 certain parties submitted a petition for writ of certiorari to the U.S. Supreme Court seeking review of the Seventh Circuit decision. The U.S. Supreme Court had not acted on the request as of February 14, 2014.

On November 12, 2013 a group of industrial customers and other stakeholders filed a complaint at the FERC seeking to reduce the return on equity 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% return on equity used in MISO's transmission rates to a proposed 9.15%. MISO and a group of MISO transmission owners have filed responses to the complaint seeking its dismissal and defending the current return on equity. The complaint is pending at the FERC.

Effective January 1, 2012 the FERC authorized OTP to recover 100% 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.

The Big Stone South - Brookings Project—This planned 345 kiloVolt (kV) transmission line will extend 70 miles between a proposed substation near Big Stone City, South Dakota and the new Brookings County Substation near Brookings, South Dakota. OTP is jointly developing this project with Xcel Energy. 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. A portion of this line is anticipated to use previously obtained Big Stone II transmission route permits and easements and is expected to be in service in the fourth quarter of 2017. On July 31, 2012 the SDPUC approved the transfer of the Big Stone II transmission route permits to OTP. In December 2012, a request was filed with the SDPUC for recertification of a portion of the line route that was approved as part of the Big Stone II transmission development. The SDPUC approved the certification for the northern portion of the route on April 9, 2013. OTP and Xcel Energy jointly submitted an application to the SDPUC for a route permit for the southern portion of the Big Stone South to Brookings line on June 3, 2013. A decision on the permit application for the southern half of this route is expected in the first quarter of 2014.

The Big Stone South - Ellendale Project—This transmission line is a proposed 345 kV 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 the ten miles of the proposed line to be built in North Dakota. A joint route permit application was filed by OTP and MDU on August 23, 2013 with the SDPUC. OTP and MDU jointly filed an Application for a Certificate of Corridor Compatibility along with an application for a route permit with the NDPSC on October 18, 2013. If the proposed project receives all the necessary approvals, OTP anticipates the line will be placed in service in the fourth quarter of 2019.

CapX2020

CapX2020 is a joint initiative of eleven investor-owned, cooperative, and municipal utilities in Minnesota and the surrounding region to upgrade and expand the electric transmission grid to ensure continued reliable and affordable service. The CapX2020 companies identified four major transmission projects for the region: (1) the Fargo-Monticello 345 kiloVolt (kV) Project (the Fargo Project), (2) the Brookings-Southeast Twin Cities 345 kV Project (the Brookings Project), (3) the Bemidji-Grand Rapids 230 kV Project (the Bemidji Project), and (4) the Twin Cities-LaCrosse 345 kV Project. OTP is an investor in the Fargo Project, the Brookings Project and the Bemidji Project. Recovery of OTP's CapX2020 transmission investments will be through the MISO Tariff (the Brookings Project as an MVP) and Minnesota, North Dakota and South Dakota TCR Riders.

The Fargo Project—All major permits have been received from state regulatory bodies and project agreements have been signed for the construction of the Fargo Project. The Monticello to St. Cloud portion of the Fargo Project was

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

placed into service on December 21, 2011. Construction is underway for the remaining portions of the project, with completion scheduled for second quarter 2015.

The Brookings Project—All major permits have been received from state regulatory bodies and project agreements have been signed for the construction of the Brookings Project. The MISO granted unconditional approval of the Brookings Project as an MVP under the MISO Tariff in December 2011. This project is anticipated to be completed in the first quarter of 2015.

The Bemidji Project—The Bemidji-Grand Rapids transmission line was fully energized and put into service on September 17, 2012.

Big Stone Plant AQCS

The South Dakota Department of Environment and Natural Resources (DENR) determined that the Big Stone Plant is subject to BART requirements of the Clean Air Act (CAA), based on air dispersion modeling indicating that Big Stone's emissions reasonably contribute to visibility impairment in national parks and wilderness areas in Minnesota, North Dakota, South Dakota and Michigan. Under the U.S. Environmental Protection Agency's (EPA) regional haze regulations, South Dakota developed and submitted its implementation plan and associated implementation rules to the EPA on January 21, 2011. The DENR and the EPA have agreed on non-substantive rule revisions, which were adopted by the Board of Minerals and Environment and became effective on September 19, 2011.

South Dakota developed and submitted its revised implementation plan and associated implementation rules to the EPA on September 19, 2011. Under the South Dakota implementation plan, and its implementing rules, the Big Stone Plant must install and operate a new BART compliant AQCS to reduce emissions as expeditiously as practicable, but no later than five years after the EPA's approval of South Dakota's implementation plan. On March 29, 2012 the EPA took final action to approve South Dakota's Regional Haze State Implementation Plan (SIP), finding that South Dakota's SIP submittal met all applicable regional haze regulations. The EPA's final approval of the SIP was effective on May 29, 2012.

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.

Minnesota—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 (which excluded \$3.2 million of transmission-related project costs). Because OTP will not 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 980 accounting requirements.

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 in the first quarter of 2013. The remaining costs, along with accumulated AFUDC, were transferred from CWIP to the Big Stone II Unrecovered Project Costs - Minnesota regulatory asset account in May 2013, based on recovery granted in the April 25, 2011 order. Because OTP will not earn a return on these deferred costs over their anticipated recovery period, the recoverable amount of approximately \$3.5 million was

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

discounted to its present value of \$2.8 million 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. The amount of the discount is expected to be recovered, along with the remaining balance of the Big Stone II Unrecovered Project Costs - Minnesota regulatory asset, over an anticipated 89-month recovery period which began in May 2013.

North Dakota—In an order issued June 25, 2010, the NDPSC authorized recovery of Big Stone II development costs from North Dakota ratepayers, pursuant to a final settlement agreement filed June 23, 2010, between the NDPSC advocacy staff, OTP and the North Dakota Large Industrial Energy Group, Interveners. The terms of the settlement agreement indicate that OTP's discontinuation of participation in the project was prudent and OTP should be authorized to recover the portion of costs it incurred related to the Big Stone II generation project. The total amount of Big Stone II generation costs incurred by OTP (which excluded \$2.6 million of project transmission-related costs) was determined to be \$10.1 million, of which \$4.1 million represents North Dakota's jurisdictional share.

OTP is including in its total recovery amount a carrying charge of approximately \$0.3 million on the North Dakota share of Big Stone II generation costs for the period from September 1, 2009 through the date the recovery of costs begins based on OTP's average 2009 AFUDC rate of 7.65%. Because OTP will 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 Stone II generation costs is being 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.

South Dakota—OTP requested recovery of the South Dakota portion of its Big Stone II development costs over a five-year period as part of its general rate case filed in South Dakota on August 20, 2010. In the first quarter of 2011, the SDPUC approved recovery of the South Dakota portion of Big Stone II generation development costs totaling approximately \$1.0 million from South Dakota ratepayers over a ten-year period beginning in February 2011 with the implementation of interim rates. OTP is allowed to earn a return on the amount subject to recovery over the ten-year recovery period. Therefore, the South Dakota settlement amount is not discounted. OTP transferred the South Dakota portion of the remaining Big Stone II transmission costs to CWIP, with such costs subject to AFUDC and recovery in future FERC-approved MISO rates or retail rates. On July 31, 2012 the SDPUC approved the transfer of the Big Stone II transmission route permits to OTP.

A portion of the Big Stone II transmission costs were transferred out of CWIP in February 2013 to be included within the Big Stone South - Brookings MVP. On March 28, 2013, OTP filed a petition with the SDPUC requesting deferred accounting for the remaining unrecovered Big Stone II Transmission costs until OTP's next South Dakota general rate case. The petition was approved by the SDPUC on April 23, 2013 and in May 2013 OTP transferred the remaining South Dakota jurisdictional portion of unrecovered Big Stone II transmission costs plus accumulated AFUDC totaling \$0.2 million from CWIP to the Big Stone II Unrecovered Project Costs - South Dakota long-term regulatory asset account.

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

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

incentives or returns on investment in such items as transmission infrastructure, renewable energy resources or conservation initiatives. The following tables indicate the amount of regulatory assets and liabilities recorded on OTP's balance sheets:

<i>(in thousands)</i>	December 31, 2013 Total	Remaining Recovery/ Refund Period
Regulatory Assets:		
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits ¹	\$ 59,107	see note
Deferred Marked-to-Market Losses ¹	11,682	60 months
Conservation Improvement Program Costs and Incentives ²	8,905	18 months
Accumulated ARO Accretion/Depreciation Adjustment ¹	4,646	asset lives
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up ¹	3,104	24 months
North Dakota Environmental Cost Recovery Rider Accrued Revenues ²	2,331	12 months
Deferred Income Taxes ¹	1,805	asset lives
North Dakota Renewable Resource Rider Accrued Revenues ²	762	15 months
Minnesota Renewable Resource Rider Accrued Revenues ²	68	see note
South Dakota Transmission Rider Accrued Revenues ²	32	12 months
Deferred Holding Company Formation Costs ¹	27	6 months
General Rate Case Recoverable Expenses - South Dakota ¹	6	1 month
Total Regulatory Assets	\$ 92,475	
Regulatory Liabilities:		
Deferred Income Taxes	\$ 1,960	asset lives
Minnesota Transmission Rider Accrued Refund	670	12 months
Revenue for Rate Case Expenses Subject to Refund - Minnesota	289	see note
North Dakota Renewable Resource Rider Accrued Refund	261	12 months
North Dakota Transmission Rider Accrued Refund	215	12 months
Deferred Marked-to-Market Gains	123	56 months
Deferred Gain on Sale of Utility Property - Minnesota Portion	111	240 months
South Dakota - Nonasset-Based Margin Sharing Excess	38	12 months
Total Regulatory Liabilities	\$ 3,667	
Net Regulatory Asset Position	\$ 88,808	

¹ Costs subject to recovery without a rate of return.

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

<i>(in thousands)</i>	December 31, 2012 Total	Remaining Recovery/ Refund Period
Regulatory Assets:		
Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits ¹	\$ 117,950	see note
Deferred Marked-to-Market Losses ¹	17,999	72 months
Conservation Improvement Program Costs and Incentives ²	6,267	18 months

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Accumulated ARO Accretion/Depreciation Adjustment ¹	4,137	asset lives
Deferred Income Taxes ¹	1,691	asset lives
North Dakota Renewable Resource Rider Accrued Revenues ²	1,619	15 months
MISO Schedule 26/26A Transmission Cost Recovery Rider True-up ¹	1,352	see note
Minnesota Renewable Resource Rider Accrued Revenues ²	915	5 months
General Rate Case Recoverable Expenses ¹	285	13 months
North Dakota Transmission Rider Accrued Revenues ²	110	12 months
Deferred Holding Company Formation Costs ¹	82	18 months
South Dakota Transmission Rider Accrued Revenue ²	2	12 months
Total Regulatory Assets	\$ 152,409	
Regulatory Liabilities:		
Deferred Income Taxes	\$ 2,553	asset lives
Minnesota Transmission Rider Accrued Refund	489	12 months
Deferred Marked-to-Market Gains	217	68 months
Deferred Gain on Sale of Utility Property - Minnesota Portion	118	252 months
South Dakota - Nonasset-Based Margin Sharing Excess	56	12 months
Total Regulatory Liabilities	\$ 3,433	
Net Regulatory Asset Position	\$ 148,976	

¹ Costs subject to recovery without a rate of return.

² 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 Gains and Losses recorded as of December 31, 2013 are related to forward purchases of energy scheduled for delivery through December 2018.

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.

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. The December 31, 2013 balance will be amortized on a straight-line basis over two consecutive 12-month periods beginning in January 2014.

North Dakota Environmental Cost Recovery Rider Accrued Revenues relate to a return granted on the North Dakota share of amounts invested in the construction of the Big Stone Plant AQCS project. The rider, approved in December 2013, is retroactive to January 2013. The balance in the regulatory asset account is subject to recovery over a twelve

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

month period ending on December 31, 2014.

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

North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of December 31, 2013.

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 as of December 31, 2013. A supplemental filing was submitted to the MPUC on February 15, 2013, requesting that the then current MNRRA rate be retained until a majority of the remaining costs were recovered and that the MNRRA rate be set to zero effective May 1, 2013. The MPUC approved the request on April 4, 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 Rider Accrued Revenues relate to revenues billed for qualifying transmission system facilities and operating costs incurred to serve South Dakota customers net of transmission revenues that have not been billed to South Dakota customers as of December 31, 2013.

General Rate Case Recoverable Expenses - South Dakota relate to expenses incurred during rate case proceedings that are eligible for recovery.

The Minnesota Transmission Rider Accrued Refund relates to revenues earned on qualifying transmission system facilities and operating costs incurred to serve Minnesota customers net of transmission revenues that are refundable to Minnesota customers as of December 31, 2013.

Revenue for Rate Case Expenses Subject to Refund - Minnesota relate 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 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, 2013.

The North Dakota Transmission Rider Accrued Refund relates to amounts collected for qualifying transmission system facilities and operating costs incurred to serve North Dakota customers net of transmission revenues that are refundable to North Dakota customers as of December 31, 2013.

South Dakota - Nonasset-Based Margin Sharing Excess represents 25% of OTP's South Dakota share of actual profit margins on nonasset-based wholesale sales of electricity. The excess margins accumulated annually will be subject to refund through future retail rate adjustments in South Dakota in the following year.

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 extraordinary 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 do not meet the definition of capacity contracts are considered derivatives subject to mark-to-market accounting. OTP's objective in entering into

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

forward contracts for the purchase and sale of energy is to optimize the use of its generating and transmission facilities and leverage its knowledge of wholesale energy markets in the region to maximize financial returns for the benefit of both its customers and shareholders. OTP's intent in entering into certain of these contracts is to settle them through the physical delivery of energy when physically possible and economically feasible. OTP also enters into certain contracts for trading purposes with the intent to profit from fluctuations in market prices through the timing of purchases and sales.

As of December 31, 2013 OTP had recognized, on a pretax basis, \$115,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. Market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The fair value measurements of these forward energy contracts fall into Level 3 of the fair value hierarchy set forth in ASC 820.

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

<i>(in thousands)</i>	2013	2012
Wholesale Sales - Company-Owned Generation	\$ 14,846	\$ 12,951
Revenue from Settled Contracts at Market Prices	133,238	160,987
Market Cost of Settled Contracts	(132,055)	(159,500)
Net Margins on Settled Contracts at Market	1,183	1,487
Marked-to-Market Gains on Settled Contracts	3,039	7,864
Marked-to-Market Losses on Settled Contracts	(2,722)	(7,974)
Net Marked-to-Market Gains (Losses) on Settled Contracts	317	(110)
Unrealized Marked-to-Market Gains on Open Contracts	215	284
Unrealized Marked-to-Market Losses on Open Contracts	(100)	(235)
Net Unrealized Marked-to-Market Gains on Open Contracts	115	49
Wholesale Electric Revenue	\$ 16,461	\$ 14,377

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and the location and fair value amounts of the related derivatives reported on OTP's balance sheets as of December 31, 2013 and December 31, 2012, and the change in OTP's balance sheet position from December 31, 2012 to December 31, 2013 and December 31, 2011 to December 31, 2012:

<i>(in thousands)</i>	December 31, 2013	December 31, 2012
Other Current Asset - Marked-to-Market Gain	\$ 338	\$ 502
Regulatory Asset - Current Deferred Marked-to-Market Loss	3,008	7,949
Regulatory Asset - Long-Term Deferred Marked-to-Market Loss	8,674	10,050
Total Assets	12,020	18,501
Current Liability - Marked-to-Market Loss	(11,782)	(18,234)
Regulatory Liability - Current Deferred Marked-to-Market Gain	(6)	(8)
Regulatory Liability - Long-Term Deferred Marked-to-Market Gain	(117)	(210)

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Total Liabilities	(11,905)	(18,452)
Net Fair Value of Marked-to-Market Energy Contracts	\$ 115	\$ 49

<i>(in thousands)</i>	2013	2012
Cumulative Fair Value Adjustments Included in Earnings - Beginning of Period	\$ 49	\$ 894
Less: Amounts Realized on Settlement of Contracts Entered into in Prior Periods	(49)	(861)
Changes in Fair Value of Contracts Entered into in Prior Periods	--	(33)
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	--	--
Changes in Fair Value of Contracts Entered into in Current Period	115	49
Cumulative Fair Value Adjustments Included in Earnings - End of Period	\$ 115	\$ 49

The \$115,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on December 31, 2013 is expected to be realized on settlement in the first quarter of 2014.

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. 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.

The following table provides information on OTP's credit risk exposure on delivered and marked-to-market forward contracts as of December 31, 2013 and December 31, 2012:

<i>(in thousands)</i>	December 31, 2013		December 31, 2012	
	Exposure	Counterparties	Exposure	Counterparties
Net Credit Risk on Forward Energy Contracts	\$ 856	3	\$ 580	6
Net Credit Risk to Single Largest Counterparty	\$ 530		\$ 285	

OTP had a net credit risk exposure to three counterparties with investment grade credit ratings. OTP had no exposure at December 31, 2013 or December 31, 2012 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch). The credit risk exposures include net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains on forward contracts for the purchase of gasoline scheduled for settlement subsequent to December 31, 2013. Individual counterparty exposures are 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 amounts of derivative asset and derivative liability balances that were subject to legally enforceable netting arrangements as of December 31, 2013 and December 31, 2012 are indicated in the following table:

<i>(in thousands)</i>	December 31, 2013	December 31, 2012
Derivative Assets Subject to Legally Enforceable Netting Arrangements	\$ 400	\$ 638
Derivative Liabilities Subject to Legally Enforceable Netting Arrangements	(11,782)	(18,234)
Net Balance Subject to Legally Enforceable Netting Arrangements	\$ (11,382)	\$ (17,596)

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, 2013 and December 31, 2012:

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

	December 31, 2013	December 31, 2012
Current Liability - Marked-to-Market Loss <i>(in thousands)</i>		
Loss Contracts Covered by Deposited Funds or Letters of Credit	\$ --	\$ 2,176
Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade ¹	11,679	16,058
Loss Contracts with No Ratings Triggers or Deposit Requirements	103	--
Total Current Liability - Marked-to-Market Loss	\$ 11,782	\$ 18,234

¹Certain OTP derivative energy contracts contain provisions that require an investment grade credit rating from each of the major credit rating agencies on OTP's debt. If OTP's debt ratings were to fall below investment grade, the counterparties to these forward energy contracts could request the immediate deposit of cash to cover contracts in net liability positions.

Contracts Requiring Cash Deposits if OTP's Credit Falls Below Investment Grade	\$ 11,679	\$ 16,058
Offsetting Gains with Counterparties under Master Netting Agreements	(117)	(416)
Reporting Date Deposit Requirement if Credit Risk Feature Triggered	\$ 11,562	\$ 15,642

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 2013 Otter Tail Corporation made cash equity contributions to OTP totaling \$22,400,000. In 2012 Otter Tail Corporation made a \$20,000,000 cash equity contribution to OTP.

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, 2013 Otter Tail Corporation and OTP were 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 44.8% and 54.8%. OTP's equity to total capitalization ratio including short-term debt was 50.2% as of December 31, 2013. Total capitalization for OTP cannot currently exceed \$874 million.

7. Commitments and Contingencies

Construction and Other Purchase Commitments

At December 31, 2013 OTP had commitments under contracts in connection with construction programs aggregating approximately \$108,227,000.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 through 2038. 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 2014, 2015, 2016 and 2040. 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 continuing operations was \$2,641,000 for 2013 and \$2,521,000 for 2012.

The amounts of OTP's commitments under capacity and energy agreements, coal and coal delivery contracts and operating leases as of December 31, 2013, are as follows:

<i>(in thousands)</i>	Capacity and Energy Requirements	Coal and Freight Purchase Commitments	Operating Leases
2014	\$ 22,565	\$ 50,149	\$ 2,519
2015	30,468	20,790	1,649
2016	22,812	21,041	1,309
2017	22,123	23,599	978
2018	25,808	23,135	989
Beyond 2018	223,561	621,814	11,812
Total	\$ 347,337	\$ 760,528	\$ 19,256

Other

OTP is a party to litigation 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 results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2013 will not be material.

8. Short-Term and Long-Term Borrowings

Short-Term Debt

The following table presents the status of OTP's line of credit as of December 31, 2013 and December 31, 2012:

<i>(in thousands)</i>	Line Limit	In Use on December 31, 2013	Restricted due to Outstanding Letters of Credit	Available on December 31, 2013	Available on December 31, 2012
OTP Credit Agreement	\$ 170,000	\$ 51,195	\$ 1,830	\$ 116,975	\$ 166,811

Under the OTP Credit Agreement referenced below, the maximum amount of debt outstanding in 2013 was \$53,003,000 on December 13, 2013 and the average daily balance of debt outstanding during 2013 was \$17,446,000. The weighted average interest rate paid on debt outstanding under the OTP Credit Agreement during 2013 was 1.4% compared with 1.7% in 2012.

On October 29, 2012 OTP entered into a Second Amended and Restated Credit Agreement (the OTP Credit Agreement)

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

with the Banks named therein, 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, 2013 the OTP Credit Agreement was amended to extend its expiration date by one year from October 29, 2017 to October 29, 2018. 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 the OTP Credit Agreement bear interest at LIBOR plus 1.25%, subject to adjustment based on the ratings of OTP's senior unsecured debt. The interest rate being charged under the OTP Credit Agreement prior to the renewal was LIBOR plus 1.5%. Under the OTP Credit Agreement, 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 certain financial covenants as described below under the heading "Financial Covenants," as well as a financial covenant under which OTP may not permit the ratio of its "Interest-bearing Debt" to "Total Capitalization" (as defined in the OTP Credit Agreement) to be greater than 0.60 to 1.00. 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 Issuances and Retirements

Unsecured Term Loan due January 15, 2015

On March 1, 2013 OTP entered into a Credit Agreement (the Loan Agreement) with JPMorgan Chase Bank, N.A. (JPMorgan) providing for a \$40.9 million unsecured term loan (the Term Loan) to OTP originally due on June 1, 2014, which was fully drawn on March 1, 2013. The Loan Agreement was amended on October 29, 2013 to extend the due date on the Term Loan to January 15, 2015.

Borrowings under the Loan Agreement bore interest at LIBOR plus 0.875%. On March 1, 2013, OTP utilized approximately \$25.1 million of Term Loan proceeds to fund the redemption price for all of the 4.65% Grant County, South Dakota Pollution Control Refunding Revenue Bonds and 4.85% Mercer County, North Dakota Pollution Control Refunding Revenue Bonds outstanding on that date, in each case for which OTP pays debt service. All such bonds had been called for redemption in full on March 1, 2013. Also on March 1, 2013, OTP utilized approximately \$15.7 million of Term Loan proceeds to satisfy an intercompany note to Otter Tail Corporation that had a balance and interest rate designed to equate to the balances and dividend rates of Otter Tail Corporation's cumulative preferred shares. On February 27, 2014, OTP used a portion of the proceeds of the New OTP Notes described below to retire early the Term Loan.

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 2029 Notes) and \$90 million aggregate principal amount of OTP's 5.47% Series B Senior Unsecured Notes due February 27, 2044 (the 2044 Notes and, together with the 2029 Notes, the New OTP Notes). The New OTP Notes were issued on February 27, 2014. OTP used a portion of the proceeds of the New OTP Notes to retire early the Term Loan as discussed above and to repay short-term debt outstanding on February 27, 2014. The remaining proceeds of the New OTP Notes will be used to pay fees and expenses related to the issuance of the New OTP Notes and for other general purposes, including planned construction program expenditures.

The 2013 Note Purchase Agreement states that OTP may prepay all or any part of the New OTP Notes (in an amount not less than 10% of the aggregate principal amount of the New OTP 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

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

prepayment made by OTP of (i) all of the 2029 Notes then outstanding on or after November 27, 2028 or (ii) all of the 2044 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 New OTP 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 New OTP Notes than any analogous provision contained in the 2013 Note Purchase Agreement (an "Additional Covenant"), then unless waived by the Required Holders (as defined in the 2013 Note Purchase Agreement), the Additional Covenant will be deemed to be incorporated into the 2013 Note Purchase Agreement. The 2013 Note Purchase Agreement also provides for the amendment, modification or deletion of an Additional Covenant if such Additional Covenant is amended or modified under or deleted from the OTP credit agreement, provided that no default or event of default has occurred and is continuing.

2007 and 2011 Note Purchase Agreements

On December 1, 2011, OTP issued \$140 million aggregate principal amount of its 4.63% Senior Unsecured Notes due December 1, 2021 (the 2021 Notes) pursuant to a Note Purchase Agreement dated as of July 29, 2011 (the 2011 Note Purchase Agreement). OTP used a portion of the proceeds of the 2021 Notes to retire \$90 million aggregate principal amount of its 6.63% Senior Notes due December 1, 2011 at maturity and to retire early \$10.4 million aggregate principal amount of outstanding pollution control refunding revenue bonds due December 1, 2012. No penalty was paid for the early retirement.

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

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

below under the heading "Financial Covenants."

Shelf Registration

On May 11, 2012 Otter Tail Corporation filed a shelf registration statement with the SEC under which it may offer for sale, from time to time, either separately or together in any combination, equity and/or debt securities described in the shelf registration statement, which expires on May 10, 2015.

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2013 for each of the next five years are:

<i>(in thousands)</i>	2014	2015	2016	2017	2018
Aggregate amounts of Debt Maturities	\$ --	\$ 40,900	\$ --	\$ 33,000	\$ --

Financial Covenants

OTP was in compliance with the financial covenants in its debt agreements as of December 31, 2013.

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 and the Loan Agreement (when in effect), 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

OTP's noncontributory funded pension plan (the Plan) covers substantially all OTP nonunion employees hired prior to January 1, 2006, and all OTP union employees 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. The Plan is subject to discontinuance, but no change or discontinuance may affect the pensions theretofore vested.

The 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.

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) 12/31/2013	2013/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Components of net periodic pension benefit cost:

<i>(in thousands)</i>	2013	2012
Service Cost-Benefit Earned During the Period	\$ 5,448	\$ 4,952
Interest Cost on Projected Benefit Obligation	11,808	12,141
Expected Return on Assets	(14,143)	(14,055)
Amortization of Prior-Service Cost from Regulatory Asset	333	398
Amortization of Net Actuarial Loss from Regulatory Asset	6,600	4,910
Net Periodic Pension Cost	\$ 10,046	\$ 8,346

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

	2013	2012
Discount Rate	4.50%	5.15%
Long-Term Rate of Return on Plan Assets	7.75%	8.00%
Rate of Increase in Future Compensation Level	3.13%	3.38%

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

<i>(in thousands)</i>	2013	2012
Regulatory Assets:		
Unrecognized Prior Service Cost	\$ 776	\$ 1,109
Unrecognized Actuarial Loss	56,051	98,808
Total Regulatory Assets	\$ 56,827	\$ 99,917
Noncurrent Liability	\$ 39,371	\$ 82,416

Funded status as of December 31:

<i>(in thousands)</i>	2013	2012
Accumulated Benefit Obligation	\$(218,532)	\$(232,500)
Projected Benefit Obligation	\$(247,434)	\$(268,467)
Fair Value of Plan Assets	208,063	186,051
Funded Status	\$ (39,371)	\$ (82,416)

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, 2013:

<i>(in thousands)</i>	2013	2012
Reconciliation of OTP's Portion of the Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	\$ 186,051	\$ 164,219
Actual Return on Plan Assets	22,348	21,964
Discretionary Company Contributions	10,000	10,000
Benefit Payments	(10,336)	(10,132)
Fair Value of Plan Assets at December 31	\$ 208,063	\$ 186,051
Estimated Asset Return	11.8%	13.4%
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 268,467	\$ 239,699
Service Cost	5,448	4,952
Interest Cost	11,808	12,141

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Benefit Payments	(10,336)	(10,132)
Actuarial (Gain) Loss	(27,953)	21,807
Projected Benefit Obligation at December 31	\$ 247,434	\$ 268,467

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

	2013	2012
Discount Rate	5.30%	4.50%
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 2014 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 pension plan investment advisors, as well as input from actuaries who work with the pension plan.

Market-related value of plan assets—OTP's 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 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:	2013	2012
Net Periodic Pension Cost	January 1, 2013	January 1, 2012
End of Year Benefit Obligations	January 1, 2013 projected to December 31, 2013	January 1, 2012 projected to December 31, 2012
Market Value of Assets	December 31, 2013	December 31, 2012

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 2014 are:

<i>(in thousands)</i>	2014
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 257
Amortization of Unrecognized Actuarial Loss	3,477
Total Estimated Amortization	\$ 3,734

Cash flows—The Plan had no minimum funding requirement as of December 31, 2013, but OTP made discretionary plan contributions totaling \$20,000,000 in January 2014.

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

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) 12/31/2013	2013/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

<i>(in thousands)</i>	2014	2015	2016	2017	2018	Years 2019-2023
	\$11,187	\$11,650	\$12,234	\$12,878	\$13,657	\$79,732

The following objectives guide the investment strategy of the Plan:

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

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

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

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

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.

The Plan asset allocations at December 31, 2013 and 2012, by asset category are as follows:

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Asset Allocation	2013	2012
Large Capitalization Equity Securities	21.0%	24.7%
International Equity Securities	21.7%	17.8%
Small and Mid-Capitalization Equity Securities	8.5%	7.1%
SEI Dynamic Asset Allocation Fund	5.2%	4.8%
Equity Securities	56.4%	54.4%
Fixed-Income Securities and Cash	39.3%	41.1%
Other - SEI Special Situation Collective Investment Trust	4.3%	4.5%
	100.0%	100.0%

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 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.

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 table presents, for each of these hierarchy levels, OTP's share of pension fund assets measured at fair value as of December 31, 2013 and 2012:

2013 (in thousands)	Level 1	Level 2	Level 3
Large Capitalization Equity Securities Mutual Fund	\$ 43,715		
International Equity Securities Mutual Funds	45,205		
Small and Mid-Capitalization Equity Securities Mutual Fund	17,679		
SEI Dynamic Asset Allocation Mutual Fund	10,869		
Fixed Income Securities Mutual Funds	81,663		
Cash Management - Money Market Fund	--		
SEI Special Situation Collective Investment Trust Fund		\$ 8,932	
Total Assets	\$ 199,131	\$ 8,932	\$ --
2012 (in thousands)			
Large Capitalization Equity Securities Mutual Fund	\$ 45,859		
International Equity Securities Mutual Funds	33,202		
Small and Mid-Capitalization Equity Securities Mutual Fund	13,259		
SEI Dynamic Asset Allocation Mutual Fund	8,938		
Fixed Income Securities Mutual Funds	76,439		

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Cash Management - Working Capital Account	11		
SEI Special Situation Collective Investment Trust Fund			\$ 8,343
Total Assets	\$ 177,708	\$ --	\$ 8,343

The investments held by the SEI Special Situation Collective Investment Trust on December 31, 2013 and 2012 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 net asset value 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 the management team. These assets were classified as Level 3 in 2012 because there were restrictions on trading shares in the fund that made the shares illiquid. In 2013, the restriction on the shares held by the Plan was lifted and shares in the fund could be redeemed at net asset value, so the investment in the fund was reclassified to Level 2. There were no other transfers between Levels of the fair value hierarchy during the year ended December 31, 2013.

Executive Survivor and Supplemental Retirement Plan (ESSRP)

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

Components of net periodic pension benefit cost:

<i>(in thousands)</i>	2013	2012
Service Cost-Benefit Earned During the Period	\$ 40	\$ 45
Interest Cost on Projected Benefit Obligation	763	857
Amortization of Prior Service Cost:		
From Regulatory Asset	22	22
From Other Comprehensive Income ¹	20	20
Amortization of Net Actuarial Loss:		
From Regulatory Asset	208	175
From Other Comprehensive Income ¹	193	162
Net Periodic Pension Cost	\$ 1,246	\$ 1,281

¹Amortization of Prior Service Costs 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:

	2013	2012
Discount Rate	4.50%	5.15%
Rate of Increase in Future Compensation Level	3.25%	4.59%

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

<i>(in thousands)</i>	2013	2012
Regulatory Assets:		
Unrecognized Prior Service Cost	\$ 113	\$ 135
Unrecognized Actuarial Loss	1,971	2,788
Total Regulatory Assets	\$ 2,084	\$ 2,923

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Projected Benefit Obligation Liability - Net Amount Recognized	\$ (16,093)	\$ (17,600)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	\$ 105	\$ 125
Unrecognized Actuarial Loss	1,829	2,586
Total Accumulated Other Comprehensive Loss	\$ 1,934	\$ 2,711

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, 2013 and a statement of the funded status as of December 31 of both years:

<i>(in thousands)</i>	2013	2012
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	1,137	1,259
Benefit Payments	(1,137)	(1,259)
Fair Value of Plan Assets at December 31	\$ --	\$ --
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	\$ 17,600	\$ 17,244
Service Cost	39	45
Interest Cost	763	857
Benefit Payments	(1,137)	(1,259)
Liability transfer from OTP to Otter Tail Corporation	--	(242)
Actuarial (Gain) Loss	(1,172)	955
Projected Benefit Obligation at December 31	\$ 16,093	\$ 17,600

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

	2013	2012
Discount Rate	5.30%	4.50%
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 2014 are:

<i>(in thousands)</i>	2014
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 22
Amortization of Unrecognized Actuarial Loss	142
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	21
Amortization of Unrecognized Actuarial Loss	132
Total Estimated Amortization	\$ 317

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:

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) 12/31/2013	2013/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

<i>(in thousands)</i>	2014	2015	2016	2017	2018	Years 2019-2023
	\$1,174	\$1,198	\$1,186	\$1,163	\$1,205	\$6,100

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. On adoption of Statement of Financial Accounting Standards No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, in January 1993, OTP elected to recognize its transition obligation related to postretirement benefits earned of approximately \$14,548,000 over a period of 20 years. There are no plan assets.

Components of net periodic postretirement benefit cost:

<i>(in thousands)</i>	2013	2012
Service Cost-Benefit Earned During the Period	\$ 1,384	\$ 1,504
Interest Cost on Projected Benefit Obligation	1,997	2,508
Amortization of Transition Obligation from Regulatory Asset	--	729
Amortization of Prior Service Cost from Regulatory Asset	205	206
Amortization of Net Actuarial Loss from Regulatory Asset	24	642
Net Periodic Postretirement Benefit Cost	\$ 3,610	\$ 5,589
Effect of Medicare Part D Subsidy	\$ (1,759)	\$ (1,986)

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

	2013	2012
Discount Rate	4.25%	5.05%

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

<i>(in thousands)</i>	2013	2012
Regulatory Asset:		
Unrecognized Prior Service Cost	\$ 540	\$ 745
Unrecognized Net Actuarial (Gain) Loss	(344)	14,364
Net Regulatory Asset	\$ 196	\$ 15,109
Projected Benefit Obligation Liability - Net Amount Recognized	\$ (44,046)	\$ (57,352)

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, 2013:

<i>(in thousands)</i>	2013	2012
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	2,004	1,938
Benefit Payments (Net of Medicare Part D Subsidy)	(4,611)	(4,259)
Participant Premium Payments	2,607	2,321
Fair Value of Plan Assets at December 31	\$ --	\$ --
Reconciliation of OTP's Portion of the Projected Benefit Obligation:		

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Projected Benefit Obligation at January 1	\$ 57,352	\$ 47,009
Service Cost (Net of Medicare Part D Subsidy)	1,384	1,504
Interest Cost (Net of Medicare Part D Subsidy)	1,997	2,508
Benefit Payments (Net of Medicare Part D Subsidy)	(4,611)	(4,259)
Participant Premium Payments	2,607	2,321
Actuarial (Gain) Loss	(14,683)	8,269
Projected Benefit Obligation at December 31	\$ 44,046	\$ 57,352

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

	2013	2012
Discount Rate	5.10%	4.25%

Assumed healthcare cost-trend rates as of December 31:

	2013	2012
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	6.47%	6.62%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	6.82%	7.01%
Rate at Which the Cost-Trend Rate is Assumed to Decline	5.00%	5.00%
Year the Rate Reaches the Ultimate Trend Rate	2025	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 2013 would have the following effects:

<i>(in thousands)</i>	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	\$ 5,168	\$ (4,333)
Effect on Total of Service and Interest Cost	\$ 617	\$ (487)
Effect on Expense	\$ 1,233	\$ (511)

Measurement Dates:	2013	2012
Net Periodic Postretirement Benefit Cost	January 1, 2013	January 1, 2012
End of Year Benefit Obligations	January 1, 2013 projected to December 31, 2013	January 1, 2012 projected to December 31, 2012

The estimated net amounts of unrecognized prior service cost to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic postretirement benefit cost in 2014 are:

<i>(in thousands)</i>	2014
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	\$ 205

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 2014. OTP expects to receive a Medicare Part D subsidy from the Federal government of approximately \$446,000 in 2014. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

<i>(in thousands)</i>						Years
2014	2014	2015	2016	2017	2018	2019-2023
	\$2,644	\$2,775	\$2,889	\$3,050	\$3,195	\$17,148

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

401K Plan

OTP has a 401K plan for the benefit of all its employees. Contributions made to this plan by OTP totaled \$1,632,000 for 2013 and \$1,320,000 for 2012.

Employee Stock Ownership Plan

OTP has a stock ownership plan for the benefit of all its employees. Contributions made by OTP were \$705,000 for 2013 and \$735,000 for 2012.

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:

Cash and Short-Term Investments—The carrying amount approximates fair value because of the short-term maturity of those instruments.

Short-Term Debt—The carrying amount approximates fair value because the debt obligation is short-term and the balance outstanding related to the OTP Credit Agreement is subject to a variable interest rate of LIBOR plus 1.25%, which approximates current market rates.

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. OTP's long-term debt subject to variable interest rates approximates fair value. 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, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-Term Investments	\$ 29	\$ 29	\$ 12,333	\$ 12,333
Short-Term Debt	(51,195)	(51,195)	--	--
Long-Term Debt	(335,900)	(363,505)	(335,635)	(389,023)

11. Property, Plant and Equipment

<i>(in thousands)</i>	December 31,	December 31,	Service Life	
	2013	2012	Range (years)	
			Low	High
Electric Plant				
Production	\$ 679,067	\$ 672,120	34	62
Transmission	270,606	261,447	40	55
Distribution	421,803	405,461	15	55
General	89,408	84,275	5	70
Electric Plant in Service	1,460,884	1,423,303		
Construction Work in Progress	184,780	75,758		
Other Property - Land	251	516		
Total Plant	1,645,915	1,499,577		
Less Accumulated Depreciation and Amortization	626,273	592,428		
Net Plant	\$ 1,019,642	\$ 907,149		

12. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2013 and 2012) to net income before total income tax expense for the following reasons:

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) 12/31/2013	2013/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

<i>(in thousands)</i>	2013	2012
Tax Computed at Federal Statutory Rate	\$ 16,630	\$ 15,902
Increases (Decreases) in Tax from:		
State Income Taxes Net of Federal Income Tax Benefit	1,721	1,733
Federal Production Tax Credit	(6,612)	(6,695)
North Dakota Wind Tax Credit Amortization - Net of Federal Taxes	(863)	(891)
Investment Tax Credit Amortization	(597)	(720)
Dividend Received/Paid Deduction	(632)	(656)
Impact of Change in Treatment of Medicare Part D Payments	--	(564)
Allowance for Funds Used During Construction - Equity	(638)	(409)
Tax Depreciation - Treasury Grant for Wind Farms	(304)	(304)
Differences Reversing in Excess of Federal Rates	(100)	(143)
Permanent and Other Differences	673	(291)
Total Income Tax Expense	\$ 9,278	\$ 6,962
Overall Effective Federal and State Income Tax Rate	19.5%	15.3%
Income Tax Expense Includes the Following:		
Current Federal Income Taxes	\$ 146	\$ 5,646
Current State Income Taxes	0	910
Deferred Federal Income Taxes ¹⁵	15,022	7,436
Deferred State Income Taxes	2,182	1,276
Federal Production Tax Credit	(6,612)	(6,695)
North Dakota Wind Tax Credit Amortization - Net of Federal Taxes	(863)	(891)
Investment Tax Credit Amortization	(597)	(720)
Total	\$ 9,278	\$ 6,962

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

<i>(in thousands)</i>	2013	2012
Deferred Tax Assets		
North Dakota Wind Tax Credits	\$ 42,241	\$ 44,172
Benefit Liabilities	25,268	24,814
Federal Production Tax Credits	17,594	21,625
Differences Related to Property	8,767	9,021
Net Operating Loss Carryforward	6,132	7,446
Investment Tax Credits	1,960	2,554
Vacation Accrual	1,417	1,379
Other	5,048	4,965
Total Deferred Tax Assets	\$ 108,427	\$ 115,976
Deferred Tax Liabilities		
Differences Related to Property	\$(263,658)	\$(258,946)
North Dakota Wind Tax Credits	(11,543)	(11,923)
Excess Tax over Book Pension	(6,906)	(6,924)
Other	(4,321)	(2,027)
Impact of State Net Operating Losses on Federal Taxes	(4,877)	(2,612)
Regulatory Asset	(5,618)	(4,859)
Renewable Resource Rider Accrued Revenue	(329)	(934)
Total Deferred Tax Liabilities	\$(293,786)	\$(288,225)

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) 12/31/2013	2013/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

Deferred Income Taxes	\$(185,359)	\$(172,249)
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Schedule of expiration of tax net operating losses and tax credits available as of December 31, 2013:

<i>(in thousands)</i>	Amount	Year of Expiration				
		2014	2015	2016	2017	2023-33
Federal Tax Credits	\$ 33,894	\$ --	\$ --	\$ --	\$ --	\$ 33,894
State Net Operating Losses	6,098	--	--	--	--	6,098
State Tax Credits	40,372	2,339	2,339	2,339	389	32,966

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 \$10.3 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>	2013	2012
Balance on January 1	\$ 4,436	\$ 11,238
Increases Related to Tax Positions for Prior Years	98	--
Decreases Related to Tax Positions for Prior Years	(295)	--
Uncertain Positions Resolved During Year	--	(6,802)
Balance on December 31	\$ 4,239	\$ 4,436

The balance of unrecognized tax benefits as of December 31, 2013 would not reduce our effective tax rate if recognized. The total amounts of unrecognized tax benefits as of December 31, 2013 is not expect to change significantly within the next 12 months. There was no amount accrued for interest on tax uncertainties as of December 31, 2013.

Otter Tail Corporation and its subsidiaries, including OTP, file a consolidated U.S. federal income tax return and various state and foreign income tax returns. As of December 31, 2013, with limited exceptions, Otter Tail Corporation is no longer subject to examinations by taxing authorities for tax years prior to 2010. On September 13, 2013 the IRS and U.S. Treasury issued final regulations on the deductibility and capitalization of expenditures related to tangible property, generally effective for tax years beginning on or after January 1, 2014. Taxpayers were allowed to elect early adoption of the regulations for the 2012 or 2013 tax year. Deferred tax liabilities at December 31, 2013 are not materially affected by the regulations. The final regulations do not impact the effect of Revenue Procedure 2013-24 issued on April 30, 2013, which provided guidance for repairs related to generation property. Among other things, the Revenue Procedure listed units of property and material components of units of property for purposes of analyzing repair versus capitalization issues. Otter Tail Corporation will likely adopt Revenue Procedure 2013-24 and the final tangible property regulations for income tax filings for tax year 2014.

13. Asset Retirement Obligations (AROs)

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

OTP recorded no new AROs in 2013.

Reconciliations of carrying amounts of the present value of OTP's legal AROs, capitalized asset retirement costs and

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) 12/31/2013	2013/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

related accumulated depreciation and a summary of settlement activity for the years ended December 31, 2013 and 2012 are presented in the following table:

<i>(in thousands)</i>	2013	2012
<u>Asset Retirement Obligations</u>		
Beginning Balance	\$ 5,207	\$ 4,808
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	(20)
Accrued Accretion	454	419
Settlements	--	--
Ending Balance	\$ 5,661	\$ 5,207
<u>Asset Retirement Costs Capitalized</u>		
Beginning Balance	\$ 1,477	\$ 1,497
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	(20)
Settlements	--	--
Ending Balance	\$ 1,477	\$ 1,477
<u>Accumulated Depreciation - Asset Retirement Costs Capitalized</u>		
Beginning Balance	\$ 407	\$ 351
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Depreciation Expense	55	56
Settlements	--	--
Ending Balance	\$ 462	\$ 407
<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, 2013 OTP had exposure to market risk associated with interest rates because it had \$51.2 million in short-term debt outstanding subject to variable interest rates indexed to LIBOR plus 1.25% under OTP's \$170 million revolving credit facility.

The majority of OTP's long-term debt 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. As of December 31, 2013 OTP had \$40.9 million of long-term debt outstanding under an unsecured term loan subject to a variable interest rate of LIBOR plus 0.875%. This debt was early retired on February 27, 2014 with proceeds from the issuance of fixed-rate debt (see Note 8 to financial statements).

OTP has not used interest rate swaps to manage net exposure to interest rate changes related to its 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 its stated objectives. OTP does not enter into interest rate transactions for speculative or trading purposes.

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

OTP has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of December 31, 2013 OTP had recognized, on a pretax basis, \$115,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity and electricity generating capacity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

The market prices used to value OTP's forward contracts for the purchases and sales of electricity and electricity generating capacity are determined by survey of counterparties or brokers used by OTP's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange and the CME Globex. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. These basis spreads are determined based on available market price information and the use of forward price curve models. The forward energy purchase contracts that are marked to market as of December 31, 2013, are 100% offset by forward energy sales contracts in terms of volumes and delivery periods but not in terms of delivery points. The differential in forward prices entered into with different delivery locations currently results in a net mark-to-market unrealized gain on OTP's forward energy contracts of \$115,000.

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 purchases and sales. Volumetric limits and loss limits are used to adequately manage the risks associated with OTP's energy trading activities. Additionally, OTP has a Value at Risk (VaR) limit to further manage market price risk. There was price risk on open positions as of December 31, 2013 where purchases were not at the same delivery points as the offsetting sales.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and the location and fair value amounts of the related derivatives reported on OTP's balance sheets as of December 31, 2013 and December 31, 2012, and the change in OTP's balance sheet position from December 31, 2012 to December 31, 2013 and December 31, 2011 to December 31, 2012:

<i>(in thousands)</i>	December 31, 2013	December 31, 2012
Current Asset - Marked-to-Market Gain	\$ 338	\$ 502
Regulatory Asset - Current Deferred Marked-to-Market Loss	3,008	7,949
Regulatory Asset - Long-Term Deferred Marked-to-Market Loss	8,674	10,050
Total Assets	12,020	18,501
Current Liability - Marked-to-Market Loss	(11,782)	(18,234)
Regulatory Liability - Current Deferred Marked-to-Market Gain	(6)	(8)
Regulatory Liability - Long-Term Deferred Marked-to-Market Gain	(117)	(210)
Total Liabilities	(11,905)	(18,452)
Net Fair Value of Marked-to-Market Energy Contracts	\$ 115	\$ 49

<i>(in thousands)</i>	Year ended December 31, 2013	Year ended December 31, 2012
Cumulative Fair Value Adjustments Included in Earnings - Beginning of Period	\$ 49	\$ 894
Less: Amounts Realized on Settlement of Contracts Entered into in Prior Periods	(49)	(861)

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Changes in Fair Value of Contracts Entered into in Prior Periods	--	(33)
Cumulative Fair Value Adjustments in Earnings of Contracts Entered into in Prior Years at End of Period	--	--
Changes in Fair Value of Contracts Entered into in Current Period	115	49
Cumulative Fair Value Adjustments Included in Earnings - End of Period	\$ 115	\$ 49

The \$115,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on December 31, 2013 is expected to be realized on settlement in the first quarter of 2014.

The following realized and unrealized net gains (losses) on forward energy contracts are included in electric operating revenues on OTP's statements of income:

<i>(in thousands)</i>	Year Ended December 31,		
	2013	2012	2011
Net Gains (Losses) on Forward Electric Energy Contracts	\$ 432	\$ (61)	\$ 926

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. 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. OTP's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of December 31, 2013 was \$530,000. As of December 31, 2013 OTP had a net credit risk exposure of \$856,000 from three counterparties with investment grade credit ratings. OTP had no exposure at December 31, 2013 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch).

The \$856,000 credit risk exposure included net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains on forward contracts for the purchase of gasoline scheduled for settlement subsequent December 31, 2013. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

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				(1,470,711)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				(156,384)
4	Total (lines 2 and 3)				(156,384)
5	Balance of Account 219 at End of Preceding Quarter/Year				(1,627,095)
6	Balance of Account 219 at Beginning of Current Year				(1,627,095)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				466,807
9	Total (lines 7 and 8)				466,807
10	Balance of Account 219 at End of Current Quarter/Year				(1,160,288)

Name of Respondent

Otter Tail Power Company

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(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

12/31/2013

Year/Period of Report

End of 2013/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(1,470,711)		
2					
3			(156,384)		
4			(156,384)	38,472,974	38,316,590
5			(1,627,095)		
6			(1,627,095)		
7					
8			466,807		
9			466,807	38,236,356	38,703,163
10			(1,160,288)		

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) 12/31/2013	Year/Period of Report End of <u>2013/Q4</u>
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**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)	1,447,894,600	1,447,894,600
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	11,312,847	11,312,847
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,459,207,447	1,459,207,447
9	Leased to Others		
10	Held for Future Use	29,656	29,656
11	Construction Work in Progress	184,779,895	184,779,895
12	Acquisition Adjustments	1,647,128	1,647,128
13	Total Utility Plant (8 thru 12)	1,645,664,126	1,645,664,126
14	Accum Prov for Depr, Amort, & Depl	626,272,583	626,272,583
15	Net Utility Plant (13 less 14)	1,019,391,543	1,019,391,543
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	622,322,815	622,322,815
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	2,396,604	2,396,604
22	Total In Service (18 thru 21)	624,719,419	624,719,419
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	1,553,164	1,553,164
33	Total Accum Prov (equals 14) (22,26,30,31,32)	626,272,583	626,272,583

Name of Respondent
Otter Tail Power Company

This Report Is:
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Date of Report
(Mo, Da, Yr)
12/31/2013

Year/Period of Report
End of 2013/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
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					31
					32
					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) 12/31/2013	2013/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, 2012	1,421,625,954
January 31, 2013	1,423,608,999
February 28, 2013	1,426,972,684
March 31, 2013	1,427,872,314
April 30, 2013	1,428,725,755
May 31, 2013	1,430,064,863
June 30, 2013	1,432,834,495
July 31, 2013	1,433,524,462
August 31, 2013	1,435,453,048
September 30, 2013	1,436,865,609
October 31, 2013	1,439,507,598
November 30, 2013	1,444,014,710
December 31, 2013	1,459,207,447
13-month average for rate-making	1,433,867,534

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, 2012	75,758,114	31,235,522	44,522,592
January 31, 2013	78,278,097	44,157,635	34,120,462
February 28, 2013	79,854,191	44,463,109	35,391,082
March 31, 2013	87,054,187	49,809,858	37,244,329
April 30, 2013	92,289,729	52,800,176	39,489,553
May 31, 2013	95,229,846	52,906,834	42,323,012
June 30, 2013	104,735,220	59,942,516	44,792,704
July 31, 2013	119,279,706	71,188,302	48,091,404
August 31, 2013	137,626,057	85,142,507	52,483,550
September 30, 2013	157,023,839	99,928,309	57,095,530
October 31, 2013	174,238,313	113,267,876	60,970,437
November 30, 2013	183,674,361	117,645,604	66,028,757
December 31, 2013	184,779,895	113,919,962	70,859,933
13-month average for rate-making			48,724,103

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

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Date of Report

(Mo, Da, Yr)

12/31/2013

Year/Period of Report

End of 2013/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Name of Respondent Otter Tail Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report 2013/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	2,908,764	3,479,918
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	4,210,738	3,479,918
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,710,632	
9	(311) Structures and Improvements	61,837,427	214,946
10	(312) Boiler Plant Equipment	202,860,000	1,956,794
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	60,589,908	5,712,497
13	(315) Accessory Electric Equipment	23,504,826	525,346
14	(316) Misc. Power Plant Equipment	5,467,567	310,204
15	(317) Asset Retirement Costs for Steam Production	294,509	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	356,264,869	8,719,787
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	307,623	
28	(331) Structures and Improvements	351,711	
29	(332) Reservoirs, Dams, and Waterways	3,148,826	609,281
30	(333) Water Wheels, Turbines, and Generators	1,057,183	
31	(334) Accessory Electric Equipment	592,375	
32	(335) Misc. Power PLant Equipment	393,335	488
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)	5,851,053	609,769
36	D. Other Production Plant		
37	(340) Land and Land Rights	126,762	
38	(341) Structures and Improvements	12,721,532	94,379
39	(342) Fuel Holders, Products, and Accessories	1,782,048	-5,775
40	(343) Prime Movers	31,658,648	57,846
41	(344) Generators	240,489,740	1,328,800
42	(345) Accessory Electric Equipment	20,011,662	756,402
43	(346) Misc. Power Plant Equipment	442,908	24,314
44	(347) Asset Retirement Costs for Other Production	1,182,022	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	308,415,322	2,255,966
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	670,531,244	11,585,522

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	2,458,669	868,007
49	(352) Structures and Improvements		
50	(353) Station Equipment	74,896,202	3,543,097
51	(354) Towers and Fixtures	4,692,263	7,664,853
52	(355) Poles and Fixtures	101,637,469	-6,854,130
53	(356) Overhead Conductors and Devices	77,617,901	4,337,592
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)	261,379,965	9,559,419
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	1,060,711	21,892
61	(361) Structures and Improvements		
62	(362) Station Equipment	67,383,704	4,427,033
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	64,643,243	1,869,493
65	(365) Overhead Conductors and Devices	45,917,036	1,321,492
66	(366) Underground Conduit		
67	(367) Underground Conductors and Devices	63,089,213	2,928,273
68	(368) Line Transformers	75,696,779	4,961,189
69	(369) Services	47,106,902	1,572,846
70	(370) Meters	31,666,341	1,371,083
71	(371) Installations on Customer Premises	4,130,400	249,581
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,744,946	186,985
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	405,439,275	18,909,867
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	29,483,515	694,630
88	(391) Office Furniture and Equipment	7,784,805	956,711
89	(392) Transportation Equipment	29,264,017	3,135,690
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	3,845,996	446,798
92	(395) Laboratory Equipment		
93	(396) Power Operated Equipment	586,116	39,218
94	(397) Communication Equipment	7,578,387	1,339,519
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	80,064,732	6,612,566
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)	80,064,732	6,612,566
100	TOTAL (Accounts 101 and 106)	1,421,625,954	50,147,292
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)	1,421,625,954	50,147,292

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
			3,326,676	48
				49
384,761		90,634	78,145,172	50
			12,357,116	51
56,403		22,239	94,749,175	52
85,505		13,572	81,883,560	53
				54
			77,461	55
				56
				57
526,669		126,445	270,539,160	58
				59
		3,416	1,086,019	60
				61
622,884		-85,322	71,102,531	62
				63
90,650		-22,239	66,399,847	64
122,851		-13,572	47,102,105	65
				66
170,086			65,847,400	67
516,830		-8,728	80,132,410	68
46,051			48,633,697	69
679,249			32,358,175	70
103,787			4,276,194	71
				72
88,598			4,843,333	73
				74
2,440,986		-126,445	421,781,711	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			1,521,896	86
216,482			29,961,663	87
750,588		-21,704	7,969,224	88
1,974,868			30,424,839	89
				90
127,946		21,704	4,186,552	91
				92
52,216			573,118	93
236,176			8,681,730	94
				95
3,358,276			83,319,022	96
				97
				98
3,358,276			83,319,022	99
12,565,799			1,459,207,447	100
				101
				102
				103
12,565,799			1,459,207,447	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) 12/31/2013	Year/Period of Report 2013/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, 2012	4,210,738
January 31, 2013	4,141,950
February 28, 2013	4,118,447
March 31, 2013	4,130,725
April 30, 2013	4,143,611
May 31, 2013	4,346,054
June 30, 2013	5,546,223
July 31, 2013	5,348,287
August 31, 2013	5,348,287
September 30, 2013	5,593,224
October 31, 2013	7,415,082
November 30, 2013	7,412,196
December 31, 2013	7,390,616
13-month average for rate-making	5,318,880

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

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

Production Plant in Service

December 31, 2012	670,531,244
January 31, 2013	670,073,298
February 28, 2013	670,037,955
March 31, 2013	670,199,023
April 30, 2013	670,255,860
May 31, 2013	670,280,292
June 30, 2013	670,590,243
July 31, 2013	671,448,779
August 31, 2013	671,405,622
September 30, 2013	671,496,449
October 31, 2013	671,676,158
November 30, 2013	672,794,232
December 31, 2013	676,176,938
13-month average for rate-making	671,305,084

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, 2012	261,379,965
January 31, 2013	261,490,218
February 28, 2013	263,067,656
March 31, 2013	262,955,563
April 30, 2013	263,017,295
May 31, 2013	263,112,282

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) 12/31/2013	2013/Q4
FOOTNOTE DATA			

June 30, 2013	263,295,196
July 31, 2013	263,282,714
August 31, 2013	263,289,003
September 30, 2013	263,410,420
October 31, 2013	263,280,057
November 30, 2013	263,378,691
December 31, 2013	270,539,160
13-month average for rate-making	263,499,863

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, 2012	405,439,275
January 31, 2013	406,532,808
February 28, 2013	408,220,672
March 31, 2013	409,053,551
April 30, 2013	409,585,423
May 31, 2013	410,350,180
June 30, 2013	411,148,136
July 31, 2013	411,390,117
August 31, 2013	413,311,526
September 30, 2013	414,253,055
October 31, 2013	415,154,435
November 30, 2013	417,076,797
December 31, 2013	421,781,711
13-month average for rate-making	411,792,130

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, 2012	80,064,732
January 31, 2013	81,370,725
February 28, 2013	81,527,955
March 31, 2013	81,533,453
April 30, 2013	81,723,566
May 31, 2013	81,976,056
June 30, 2013	82,254,698
July 31, 2013	82,054,565
August 31, 2013	82,098,610
September 30, 2013	82,112,461
October 31, 2013	81,981,866
November 30, 2013	83,352,795
December 31, 2013	83,319,022
13-month average for rate-making	81,951,577

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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32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of \$250,000 or more. Group other items of property held for future use.
2. For property having an original cost of \$250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Various			29,656
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Various			
23				
24				
25				
26				
27				
28				
29				
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31				
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34				
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36				
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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) 12/31/2013	Year/Period of Report 2013/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, 2012	9,037	20,619	29,656
January 31, 2013	9,037	20,619	29,656
February 28, 2013	9,037	20,619	29,656
March 31, 2013	9,037	20,619	29,656
April 30, 2013	9,037	20,619	29,656
May 31, 2013	9,037	20,619	29,656
June 30, 2013	9,037	20,619	29,656
July 31, 2013	9,037	20,619	29,656
August 31, 2013	9,037	20,619	29,656
September 30, 2013	9,037	20,619	29,656
October 31, 2013	9,037	20,619	29,656
November 30, 2013	9,037	20,619	29,656
December 31, 2013	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	Bottineau, ND - build new substation	179,414
2	Brookings, SD - SE Twin Cities - transmission line	2,859,611
3	Big Stone, SD - AQCS environmental project	94,784,408
4	Big Stone, SD - Brookings - transmission line	4,001,571
5	Fargo, ND - St Cloud, MN - transmission line - Phase II	22,677,217
6	Big Stone, SD - Ellendale, ND - transmission line	3,261,420
7	Oakes, ND - area transmission improvements	181,006
8	Fargo, ND - St Cloud, MN - transmission line - Phase III	23,441,793
9	Oakes, ND - area transmission improvements	305,310
10	Brookings, SD - MN Border - transmission line	467,032
11	SD/MN Border - Lyon City - transmission line	856,821
12	Lyon City - Cedar Mountain - transmission line	3,476,397
13	Helena - Cedar Mountain - transmission line	6,049,844
14	Helena - Chub Lake - transmission line	2,033,438
15	Chub Lake - Hampton - transmission line	1,180,541
16	Lyon City - Hazel Creek - transmission line	141,727
17	Cedar Mountain - Franklin - transmission line	325,559
18	Fargo, ND - St Cloud, MN - transmission line - underlying improvements	458,177
19	Beulah, ND - Coyote Station - mercury removal system	171,712
20	Fergus Falls, MN - install underground services	115,613
21	Rugby/Garrison, ND - install underground services	167,008
22	Summit, SD - replace substation transformer	623,387
23	System wide - circuit breaker replacement program	143,283
24	System wide - proactive relay upgrade	100,944
25	System wide - network equipment	334,232
26	System wide - PC life cycle replacements	320,957
27	Fergus Falls, MN - GIS software	276,258
28	Fergus Falls, MN - Hoot Lake Plant - environmental upgrade	2,631,276
29	System wide - transmission line analysis and GIS information collection	1,586,891
30	System wide - proactive substation foundation replacement	216,056
31	Plummer, MN - breaker replacement	147,978
32	Fergus Falls, MN - Hoot Lake Plant - replace air heater baskets	159,418
33	Fergus Falls, MN - Central Hydro - generator	248,194
34	Lyons County, SD - relocate transmission line	490,630
35	Oakes, ND - transmission substation	155,267
36	Danvers, MN - replace transmission line	103,807
37	Langdon, ND - Wind Farm - main bearing auto lube system	411,088
38	Fergus Falls, MN - real time system project	229,590
39	Hankinson, ND - Ellendale, ND - transmission line pole replacement	116,226
40	Detroit Lakes, MN - Highway 34 transmission line	192,004
41	Big Stone/Blair, SD - transmission line - NERC mitigation	221,693
42	Henning/Silver Lake, MN - transmission line - NERC mitigation	490,218
43	TOTAL	184,779,895

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	Bottineau, ND - 12.5 kv conversion project	439,356
2	Herman/Nashua, MN - rebuild transmission line	102,045
3	New Effington, SD - reroute distribution line	132,945
4	Devils Lake, ND - extend primary to new customer	143,703
5	Edgeley, ND - rebuild transmission line	182,731
6	Milbank, SD - rebuild line	185,559
7	Miscellaneous projects under \$100,000	7,258,540
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
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37		
38		
39		
40		
41		
42		
43	TOTAL	184,779,895

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	589,037,503	589,037,503		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	40,695,885	40,695,885		
4	(403.1) Depreciation Expense for Asset Retirement Costs	54,645	54,645		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,575,392	1,575,392		
7	Other Clearing Accounts	93,018	93,018		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	42,418,940	42,418,940		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	12,265,760	12,265,760		
13	Cost of Removal	1,664,700	1,664,700		
14	Salvage (Credit)	5,030,276	5,030,276		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	8,900,184	8,900,184		
16	Other Debit or Cr. Items (Describe, details in footnote):	-233,444	-233,444		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	622,322,815	622,322,815		

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

20	Steam Production	233,911,660	233,911,660		
21	Nuclear Production				
22	Hydraulic Production-Conventional	2,813,687	2,813,687		
23	Hydraulic Production-Pumped Storage				
24	Other Production	70,634,567	70,634,567		
25	Transmission	99,700,396	99,700,396		
26	Distribution	180,775,747	180,775,747		
27	Regional Transmission and Market Operation				
28	General	34,486,758	34,486,758		
29	TOTAL (Enter Total of lines 20 thru 28)	622,322,815	622,322,815		

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

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

Inventory costs cleared to construction or utility operating expense.

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

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

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

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

	Production *	Transmission	Distribution	General	Total
December 31, 2012	288,171,132	94,847,883	172,765,161	33,253,327	589,037,503
January 31, 2013	289,554,952	95,400,541	173,328,070	33,435,061	591,718,624
February 28, 2013	291,203,018	95,722,014	173,896,673	33,756,804	594,578,509
March 31, 2013	292,860,830	95,989,812	174,569,444	34,029,529	597,449,615
April 30, 2013	294,570,288	96,416,986	175,263,906	34,113,893	600,365,073
May 31, 2013	296,373,530	96,850,842	175,930,289	34,476,764	603,631,425
June 30, 2013	298,063,083	97,265,448	176,649,253	34,692,348	606,670,132
July 31, 2013	298,808,326	97,703,015	177,289,931	34,895,297	608,696,569
August 31, 2013	300,294,013	98,026,226	177,948,612	35,230,235	611,499,086
September 30, 2013	302,122,378	98,485,026	178,661,232	35,522,579	614,791,215
October 31, 2013	306,873,067	98,914,982	179,482,347	35,172,456	620,442,852
November 30, 2013	305,845,109	99,338,374	180,130,147	35,454,583	620,768,213
December 31, 2013	307,359,914	99,700,396	180,775,747	34,486,758	622,322,815
13-month average for rate-making	297,853,819	97,281,657	176,668,524	34,501,510	606,305,510

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

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Not applicable			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
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35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 \$	0	TOTAL	

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
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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)	11,011,796	9,036,445	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)	5,730,143	5,793,264	Production
8	Transmission Plant (Estimated)	4,159,175	4,227,947	Various
9	Distribution Plant (Estimated)	6,775,350	7,355,549	Various
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	302,639	296,809	Fleet Service
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	16,967,307	17,673,569	
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)	27,979,103	26,710,014	

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) 12/31/2013	Year/Period of Report 2013/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 plant for rate-making purposes, illustrated as follows for the current year:

	Production Plant
December 31, 2012	5,730,143
January 31, 2013	5,717,959
February 28, 2013	5,673,857
March 31, 2013	5,684,033
April 30, 2013	5,777,582
May 31, 2013	5,728,433
June 30, 2013	5,719,612
July 31, 2013	5,795,230
August 31, 2013	5,794,922
September 30, 2013	5,846,497
October 31, 2013	5,840,618
November 30, 2013	5,795,805
December 31, 2013	5,793,263
13-month average for rate-making	5,761,381

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

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

	Transmission Plant
December 31, 2012	4,159,175
January 31, 2013	4,149,718
February 28, 2013	4,147,047
March 31, 2013	4,160,123
April 30, 2013	4,070,180
May 31, 2013	4,137,950
June 30, 2013	4,104,766
July 31, 2013	4,019,128
August 31, 2013	4,025,670
September 30, 2013	3,889,947
October 31, 2013	4,055,724
November 30, 2013	4,150,828
December 31, 2013	4,227,947
13-month average for rate-making	4,099,862

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

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

	Distribution Plant
December 31, 2012	6,775,350
January 31, 2013	7,049,154
February 28, 2013	7,120,846
March 31, 2013	7,116,202

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

April 30, 2013	7,408,953
May 31, 2013	7,105,621
June 30, 2013	6,935,903
July 31, 2013	6,901,218
August 31, 2013	6,961,360
September 30, 2013	6,962,998
October 31, 2013	6,860,406
November 30, 2013	7,336,268
December 31, 2013	7,355,549
13-month average for rate-making	7,068,448

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

Consists of parts inventory at the Fleet Service Department.

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		2014	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	37,478.00		14,054.00	
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	15,685.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	21,793.00		14,054.00	
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	57		
45	Gains	202.96	57		
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.

2015		2016		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		445,044.00		1
								2
								3
				14,054.00		14,054.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						15,685.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
14,054.00		14,054.00		379,458.00		443,413.00		29
								30
								31
								32
								33
								34
								35
								36
202.96		202.97		9,945.16		10,757.01		36
				405.93		405.93		37
								38
				202.96		405.92		39
202.96		202.97		10,148.13		10,757.02		40
								41
								42
								43
				202.96	9	405.92		66 44
				202.96	9	405.92		66 45
								46

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		2014	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

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.

2015		2016		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
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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)

12/31/2013

Year/Period of Report

End of 2013/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Not applicable					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

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 cancelled proj -ND	907,648		See Note	-900,921	6,727
22	(ND PSC order issued 06/23/2010)					
23						
24	Big Stone II cancelled proj -ND					
25	(ND PSC order issued 07/30/2013)		962,959	See Note	-594,255	368,704
26						
27	Big Stone II cancelled proj -MN	2,143,915		See Note	-525,520	1,618,394
28	(MN PUC order issued 04/25/2011)					
29	-Generation					
30						
31	Big Stone II cancelled proj -MN		2,815,813	419	90,606	2,906,419
32	(MN PUC order issued 04/25/2011)					
33	- Transmission					
34						
35	Big Stone II cancelled proj -SD	811,017		407	-100,332	710,685
36	(SD PUC order issued 02/11/2010)					
37	-Generation					
38						
39	Big Stone II cancelled proj -SD		232,957	407		232,957
40	(SD PUC order issued 04/30/2013)					
41	-Transmission					
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	3,862,580	4,011,729		-2,030,422	5,843,886

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) 12/31/2013	Year/Period of Report 2013/Q4
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.: 21 Column: d

Accounts 407, 419, 440, 442, 444, and 445 were used.

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

This is North Dakota amortization, with interest.

Schedule Page: 230 Line No.: 25 Column: d

Accounts 407, 419, 440, 442, 444, and 445 were used.

Schedule Page: 230 Line No.: 25 Column: e

This is the North Dakota transmission cost amortized without interest.

Schedule Page: 230 Line No.: 27 Column: d

Accounts 407 and 419 were used.

Schedule Page: 230 Line No.: 27 Column: e

This is Minnesota amortization, with interest.

Schedule Page: 230 Line No.: 31 Column: e

This is the Minnesota transmission balance with interest accrued.

Schedule Page: 230 Line No.: 35 Column: e

This is South Dakota amortization.

Schedule Page: 230 Line No.: 39 Column: c

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

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
2	Gentilly Load Interconnection	1,265	456		
3	Turtle Lake	(4,350)	456		
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22	Courtney Wind	28,870	456	25,714	456
23					
24					
25					
26					
27					
28					
29					
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31					
32					
33					
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35					
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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	1,691,328	484,552	282	370,459	1,805,421
4						
5						
6						
7	Asset Retirement Obligation Capitalized					
8	Hoot Lake Plant	1,502,555	138,484			1,641,039
9	Big Stone Plant	355,952	37,189	407.4	120	393,021
10	Coyote Station	1,640,112	156,988			1,797,100
11	Wind Generation - Langdon	287,006	64,682			351,688
12	Wind Generation - Ashtabula	188,238	55,105			243,343
13	Wind Generation - Luverne	163,134	56,380			219,514
14						
15	Derivatives-Marked to Market Losses	17,998,558	11,781,888	244	18,098,739	11,681,707
16						
17						
18	MN MISO costs - Schedule 26 Accrual		1,752,759			1,752,759
19	MN Renewable Resource Rider	915,309	43,441	See Note	890,389	68,361
20	ND Renewable Resource Rider	1,619,288	1,713,767	See Note	2,571,219	761,836
21						
22	ESSRP	2,922,553		228.3	838,470	2,084,083
23						
24	Pension	99,917,336		228.3	43,090,910	56,826,426
25						
26	Rate Case Expense Deferral	285,169		407	279,100	6,069
27						
28	Holding Co. Formation	82,542		407	55,200	27,342
29						
30						
31						
32	MN Transmission Revenue Rider	1,351,652				1,351,652
33	ND Transmission Revenue Rider	109,815	178,816	See Note	288,631	
34	SD Transmission Revenue Rider	2,519	129,290	See Note	100,109	31,700
35						
36	ND Environmental Cost Recovery Rider		3,803,395	See Note	1,472,584	2,330,811
37						
38	Post Retirement Medical Benefits	15,109,044		228.3	14,912,671	196,373
39						
40	Conservation Improvement Program - MN	6,132,384	4,899,956	186	2,238,053	8,794,287
41	Energy Efficiency Program - SD	134,196	135,732	186	159,812	110,116
42	See footnote 3 in Notes to Financial Statements					
43	for amortization periods.					
44	TOTAL	152,408,690	25,432,424		85,366,466	92,474,648

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) 12/31/2013	Year/Period of Report 2013/Q4
FOOTNOTE DATA			

Schedule Page: 232 Line No.: 19 Column: d

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

Schedule Page: 232 Line No.: 20 Column: d

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

Schedule Page: 232 Line No.: 33 Column: d

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

Schedule Page: 232 Line No.: 34 Column: d

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

Schedule Page: 232 Line No.: 36 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		5,248,244	182.3	5,248,244	
3						
4	Energy Efficiency					
5	Program - SD		281,549	182.3	281,549	
6						
7	Purchase Card Accrual	168,706	2,701,440	186	2,704,981	165,165
8						
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	168,706				165,165

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	226,284	226,284
4	Medical Insurance Reserve		
5	Injuries and Damages Reserve		
6	See Note Below	115,749,927	108,200,464
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	115,976,211	108,426,748
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)	115,976,211	108,426,748

Notes

NOTE: Continued from above

Post Retirement Benefits	19,088,780	19,717,928
Executive Supplemental Pension	4,579,900	4,622,906
Reserve for Bad Debts	333,551	336,739
Accrued Vacation Pay	1,378,633	1,417,106
Capitalized Interest on Construction	4,538,375	4,925,937
Post Employment Benefits	362,262	99,095
Nonqualified Retirement Savings	212,679	253,659
Reserve for Loan Pools	10,802	11,445
Capitalized A&G	4,206,441	3,558,063
Customer Rebates Capitalized	113,172	87,426
Asbestos Removal Costs Capitalized	1,401	218
Stock Incentives	134,770	73,803
CIAC Capitalized	192,358	169,725
BSII Discount	132,802	80,604
Unicap Adjustment	37,332	29,524
Medicare Part D	351,908	415,542
Research Credit Carryforward	0	108,141
Charitable Contributions	860,426	1,066,134
Severance Settlement	0	40,468
Flow-through Items	249,936	217,468
State NOL Carryforward	7,445,766	6,132,148
Wind Energy Income Tax Credits - ND	44,172,134	42,240,743
ASC740 Unamortized ITC	2,553,864	1,959,731
ASC740 Recognition of Regulatory Assets (Liab.)	3,167,609	3,042,153
Wind Production Tax Credit Deferral (Asset)	21,625,026	17,593,758
	-----	-----
Total	115,749,927	108,200,464

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.

2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201 (Par)			
2	Common Stock	50,000,000	5.00	
3				
4				
5	TOTAL COMMON	50,000,000		
6				
7	Cumulative Preferred	1,500,000		
8	Cumulative Preference	1,000,000		
9	TOTAL PREFERRED	2,500,000		
10				
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Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2013

Year/Period of Report
End of 2013/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
 4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
 5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
- Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
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	229,861,391
2	Additional parent investment	22,400,000
3		
4		
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40	TOTAL	252,261,391

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) 12/31/2013	Year/Period of Report End of <u>2013/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	888,512
3	2017 Series Pollution Control Refund-BSP - Retired early on March 1, 2013	5,065,000	463,524
4	2022 Series Pollution Control Refund-CYT - Retired early on March 1, 2013	20,070,000	2,047,820
5	Senior Unsecured Notes 6.47%, Series D	50,000,000	665,975
6			
7	Senior Unsecured Notes 6.37%, Series C	42,000,000	540,768
8			
9	Senior Unsecured Notes 6.15%, Series B	30,000,000	386,988
10	Senior Unsecured Notes 5.95%, Series A	33,000,000	424,856
11	2014 Series Term Loan	40,900,000	31,657
12	Issued 3/1/2013, MN Public Utilities Commission authorization,		
13	Docket No. E017/S-13-378 dated 6/21/2013.		
14	Account 222 - Reacquired Bonds - None		
15	Account 223 - Advances from associated companies		
16	5.33% Notes-Otter Tail Corporation - Retired on March 1, 2013	6,000,000	
17			
18	7.21% Notes-Otter Tail Corporation - Retired on March 1, 2013	2,500,000	
19			
20	7.62% Notes-Otter Tail Corporation - Retired on March 1, 2013	3,000,000	
21			
22	9.35% Notes-Otter Tail Corporation - Retired on March 1, 2013	4,000,000	
23			
24	Account 224 Other Long Term Debt - None		
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	376,535,000	5,450,100

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
7/29/2011	12/1/2021	12/1/2011	11/30/2021	140,000,000	6,482,000	2
9/26/2001	9/1/2017	10/1/2001	9/1/2017		39,254	3
9/26/2001	9/1/2022	10/1/2001	9/1/2022		162,233	4
08/20/07 & 10/1/2007	8/20/2037	8/20/2007	8/20/2037	50,000,000	3,235,000	5
08/20/07 & 10/1/2007	8/20/2027	8/20/2007	8/20/2027	42,000,000	2,675,400	7
10/1/2007						8
10/1/2007	8/20/2022	10/1/2007	8/20/2022	30,000,000	1,845,000	9
10/1/2007	8/20/2017	10/1/2007	8/20/2017	33,000,000	1,963,500	10
3/1/2013	6/1/2014	3/1/2013	1/15/2015	40,900,000	369,512	11
						12
						13
						14
						15
	NA				188,300	16
						17
	NA				80,042	18
						19
	NA				83,100	20
						21
	NA				75,832	22
						23
						24
						25
						26
						27
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						29
						30
						31
						32
				335,900,000	17,199,173	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) 12/31/2013	Year/Period of Report 2013/Q4
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 30 Column: a
 Instruction 9 - Unamortized debt expense remaining on bonds retired early are 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)	38,236,356
2		
3		
4	Taxable Income Not Reported on Books	
5	Interest capitalized on construction	1,500,802
6	Net gain from property retirements	4,269,418
7	Miscellaneous taxable items	
8	Conservation Improvement Programs	-3,875,437
9	Deductions Recorded on Books Not Deducted for Return	
10	Add back Federal income taxes (includes deferreds and ITC adj.)	9,278,313
11	Provision for reserves	6,834,538
12	Miscellaneous unallowed deductions	40,440,096
13		
14	Income Recorded on Books Not Included in Return	
15	Tax exempt interest	6,167
16	Equity in earnings of subsidiaries	
17	Wind rider revenue	9,166,067
18	Miscellaneous income not taxable	
19	Deductions on Return Not Charged Against Book Income	
20	Excess tax depreciation over book depreciation	6,318,005
21	Removal costs	1,644,700
22	Charges to reserves	5,778,624
23	Leveraged ESOP deduction	1,804,841
24	Sec 481(a) Cap to repair basis adjustments	7,063,916
25	Miscellaneous other deductions	34,259,423
26		
27	Federal Tax Net Income	30,642,343
28	Show Computation of Tax:	
29	Federal tax	10,715,820
30	Tax (credits) and adjustments	-10,715,820
31	Prior period adjustments	145,594
32	Total Federal income tax	145,594
33		
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) 12/31/2013	2013/Q4
FOOTNOTE DATA			

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

**RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME
FOR FEDERAL INCOME TAXES (Continued)**

Otter Tail Power Company is a member of an affiliated group which will file a consolidated Federal Income Tax Return for the year 2013. The other members of the affiliated group and their respective federal income tax provisions are as follows:

1	Otter Tail Corporation-Corporate	(8,815,422)
2	Varistar Corporation	345,717
3	DMI Industries, Inc.	(53,784)
4	BTD Manufacturing, Inc.	5,959,257
5	Northern Pipe Products, Inc.	4,085,723
6	Vinyltech Corporation	2,973,164
7	Otter Tail Energy Services Company	0
8	T. O. Plastics, Inc.	1,602,847
9	ShoreMaster, Inc.	(3,139,419)
10	Galva Foam Marine Industries, Inc.	(417,178)
11	Otter Tail Assurance Limited	85,282
12	Aevenia, Inc.	(77,303)
13	Foley Company	299,334
14	Shoreline Industries, Inc.	(42,667)
15	Aviva Sports, Inc.	(213,158)
16	Miller Welding & Iron Works, Inc.	(1,804,391)

	Total	788,001
		=====

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	479,495		1,776,007	2,255,501	
3	Unemployment	573		232,599	232,730	
4	FICA			4,349,325	4,349,325	
5						
6	MINNESOTA					
7	Property	6,425,001		7,006,653	6,419,654	
8	Income			434,354	434,354	
9	Unemployment	1,725		96,868	96,595	
10						
11	NORTH DAKOTA					
12	Property	2,550,000		2,043,285	2,543,286	
13	Income			93,816	93,816	
14	Unemployment	276		11,829	11,825	
15	Coal Conversion	120,297		715,699	662,766	
16						
17	SOUTH DAKOTA					
18	Property	1,390,000		1,590,929	1,380,930	
19	Unemployment	95		3,067	3,069	
20						
21	OTHER STATES					
22	Income					
23	Railcar	19,501		42,926	44,983	
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	10,986,963		18,397,357	18,528,834	

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
		1,331,495			444,512	2
442					232,599	3
					4,349,325	4
						5
						6
7,012,001		7,006,653				7
		188,513			245,841	8
1,998					96,868	9
						10
						11
2,049,999		1,997,853			45,432	12
		77,493			16,323	13
280					11,829	14
173,230		715,699				15
						16
						17
1,599,999		1,590,929				18
93					3,067	19
						20
						21
						22
17,444					42,926	23
						24
						25
						26
						27
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						39
						40
10,855,486		12,908,635			5,488,722	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) 12/31/2013	Year/Period of Report 2013/Q4
FOOTNOTE DATA			

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

Account 409.2

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

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

Account 184

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

Account 921 \$45,432

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

Account 409.2

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%	28,874,452	190	-1,086,272	411.4	1,328,356	
3	4%						
4	7%						
5	10%	2,424,952			411.4	596,954	
6							
7							
8	TOTAL	31,299,404		-1,086,272		1,925,310	
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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48							

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
26,459,824	25 years		2
			3
			4
1,827,998	33.3 years		5
			6
			7
28,287,822			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
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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)
12/31/2013

Year/Period of Report
End of 2013/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than \$100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Prepaid Electric Revenue	466,174	456	41,247	292,987	717,914
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
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45						
46						
47	TOTAL	466,174		41,247	292,987	717,914

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)

12/31/2013

Year/Period of Report

End of 2013/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
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							14
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							18
							19
							20
							21

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) 12/31/2013	Year/Period of Report 2013/Q4
FOOTNOTE DATA			

Schedule Page: 272 Line No.: 3 Column: b
Not applicable.

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	273,887,732	17,103,809	12,392,051
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	273,887,732	17,103,809	12,392,051
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	273,887,732	17,103,809	12,392,051
10	Classification of TOTAL			
11	Federal Income Tax	234,973,495	13,402,193	9,623,807
12	State Income Tax	38,914,236	3,701,616	2,768,244
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
266,803	479,376				-428,954	277,957,963	2
							3
							4
266,803	479,376				-428,954	277,957,963	5
							6
							7
							8
266,803	479,376				-428,954	277,957,963	9
							10
223,922	400,826				-421,099	238,153,878	11
42,881	78,550				-7,855	39,804,084	12
							13

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) 12/31/2013	Year/Period of Report 2013/Q4
FOOTNOTE DATA			

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

Adjustment to 182.3 due to ASC 740 for (48,759) and an adjustment to 190 due to ND ITC valuation adjustment for (\$380,195).

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	13,483,607	11,321,197	12,086,376
5				
6	Accum. Deferred Income Tax			
7	Nonutility & Other	853,982		
8				
9	TOTAL Electric (Total of lines 3 thru 8)	14,337,589	11,321,197	12,086,376
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)	14,337,589	11,321,197	12,086,376
20	Classification of TOTAL			
21	Federal Income Tax	11,348,046	8,960,435	9,566,243
22	State Income Tax	2,989,543	2,360,762	2,520,133
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
					348,610	13,067,038	4
							5
							6
2,050,275	143,030					2,761,227	7
							8
2,050,275	143,030				348,610	15,828,265	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
2,050,275	143,030				348,610	15,828,265	19
							20
1,456,416	113,206				275,921	12,361,369	21
593,859	29,824				72,689	3,466,896	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) 12/31/2013	Year/Period of Report 2013/Q4
FOOTNOTE DATA			

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

228.3 Adjustment due to ASC 715-60 of \$311,210.

182.3 Adjustment due to ASC 740 of \$37,400.

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

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

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	2,553,361	190	594,134	505	1,959,732
2	ASC 740					
3						
4	Minnesota Portion of Gain on Sale of Wahpeton	117,104	407.4	5,576		111,528
5	Division Office					
6						
7	Derivatives - Mark to Market	217,449	175	614,974	520,511	122,986
8						
9	Margin Sharing - SD	56,432	See Note	66,927	48,276	37,781
10						
11	MN Transmission Revenue Rider	489,115	See Note	768,395	949,655	670,375
12						
13	SD Transmission Revenue Rider		See Note	82,105	82,105	
14						
15	ND Transmission Revenue Rider		See Note	41,808	257,281	215,473
16						
17	ND Renewable Resource Revenue Rider				260,596	260,596
18						
19	MN Future Rate Case Expense Accrual				288,793	288,793
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39	See Footnote 3 in Notes to Financial					
40	Statements for amortization periods.					
41	TOTAL	3,433,461		2,173,919	2,407,722	3,667,264

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) 12/31/2013	Year/Period of Report 2013/Q4
FOOTNOTE DATA			

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

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

Schedule Page: 278 Line No.: 11 Column: c

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

Schedule Page: 278 Line No.: 13 Column: c

Accounts 440, 442, and 445 were credited.

Schedule Page: 278 Line No.: 15 Column: c

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

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	113,434,253	104,144,744
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	125,635,483	120,824,857
5	Large (or Ind.) (See Instr. 4)	79,327,693	74,442,916
6	(444) Public Street and Highway Lighting	3,427,477	3,452,048
7	(445) Other Sales to Public Authorities	2,768,207	2,635,752
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	324,593,113	305,500,317
11	(447) Sales for Resale	14,846,056	12,951,359
12	TOTAL Sales of Electricity	339,439,169	318,451,676
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	339,439,169	318,451,676
15	Other Operating Revenues		
16	(450) Forfeited Discounts	592,316	556,298
17	(451) Miscellaneous Service Revenues	415,299	413,076
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	472,741	571,229
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	7,557,838	9,131,131
22	(456.1) Revenues from Transmission of Electricity of Others	16,224,445	13,607,785
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	25,262,639	24,279,519
27	TOTAL Electric Operating Revenues	364,701,808	342,731,195

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
1,378,859	1,253,567	102,357	101,996	2
				3
1,659,629	1,555,573	26,576	26,476	4
1,382,443	1,367,050	54	52	5
26,062	26,300	406	404	6
40,548	38,299	595	595	7
				8
				9
4,487,541	4,240,789	129,988	129,523	10
1,732,210	2,135,159			11
6,219,751	6,375,948	129,988	129,523	12
				13
6,219,751	6,375,948	129,988	129,523	14

Line 12, column (b) includes \$ 2,271,205 of unbilled revenues.

Line 12, column (d) includes 38,950 MWH relating to unbilled revenues

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) 12/31/2013	2013/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.: 4 Column: c

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.: 5 Column: c

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

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

<u>Description of Revenue</u>	<u>Current Year</u>	<u>Prior Year</u>
All others (under \$250,000 each)	<u>415,299</u>	<u>413,076</u>
Total	\$ 415,299	\$ 413,076
	=====	=====

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

<u>Description of Revenue</u>	<u>Current Year</u>	<u>Prior Year</u>
Sale of steam	\$ 2,414,903	\$ 1,849,579
Integrated transmission deficiency payments	2,739,962	4,929,695
All others (under \$250,000 each)	2,402,973	2,351,857
	-----	-----
Total	\$ 7,557,838	\$9,131,131
	=====	=====

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	938,138	87,757,978	96,205	9,751	0.0935
4						
5	Residential Service (Ctrl'd Demand					
6	9.02	162,952	11,316,423	6,300	25,865	0.0694
7						
8	Water Heating Ctrl'd (Off-Peak)					
9	14.01	41,100	2,925,182	16,614	2,474	0.0712
10				-16,614		
11	Controlled Service					
12	14.04,14.05,14.06,14.07	214,187	10,285,228	12,781	16,758	0.0480
13				-12,781		
14	Fixed Time of Delivery Service					
15	14.07	5,332	200,104	336	15,869	0.0375
16				-336		
17	Outdoor lighting-energy only					
18	11.03	68	5,577	7	9,714	0.0820
19				-7		
20	Outdoor Lighting					
21	11.04	3,950	524,500	348	11,351	0.1328
22				-348		
23	Small power producer rider					
24	12.01		283	7		
25				-7		
26	Conservation Imp Prog Rev		-567,783			
27	ND Big Stone Plant II Recvy		-35,977			
28	Environmental Rider Rev		813,477			
29	Transmission Cost Recvy		373,268			
30	Renewable Resource Rider		-666,587			
31	Fuel Clause Adjustment Rec		-241,194			
32	MN Rate Case Rev Reduction		-75,667			
33						
34	SUBTOTAL Billed	1,365,727	112,614,812	102,505	13,324	0.0825
35	Unbilled Rev (See Instr. 6)	13,132	819,441			0.0624
36	TOTAL - 440	1,378,859	113,434,253	102,505	13,452	0.0823
37						
38	Column D Lines 9,12,15,18,21&24					
39	customers are also served					
40	under other residential service.					
41	TOTAL Billed	4,448,591	322,321,908	132,738	33,514	0.0725
42	Total Unbilled Rev.(See Instr. 6)	38,950	2,271,205	0	0	0.0583
43	TOTAL	4,487,541	324,593,113	132,738	33,808	0.0723

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	768,955	67,988,807	24,416	31,494	0.0884
4						
5	Farm Service					
6	9.03	69,991	5,777,085	2,781	25,168	0.0825
7						
8	Large General Service					
9	10.03	617,106	40,084,195	390	1,582,323	0.0650
10						
11	Real Time Pricing Rider					
12	14.02	34,588	1,230,203	1	34,588,000	0.0356
13						
14	Large Gen. Srv. (Time of Day)					
15	10.05	696,682	40,096,126	93	7,491,204	0.0576
16						
17	Large General Service Rider					
18	14.03	33,876	1,456,545	14	2,419,714	0.0430
19						
20	Water Heating Ctrlld (Off-Peak)					
21	14.01	2,284	153,562	546	4,183	0.0672
22				-546		
23	Controlled Service					
24	14.04,14.05,14.06,14.07	221,785	9,281,682	4,794	46,263	0.0418
25				-4,794		
26	Fixed Time of Delivery Service					
27	14.07	25,785	936,123	527	48,928	0.0363
28				-527		
29	Irrigation Service					
30	11.02	7,336	467,274	328	22,366	0.0637
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	4,448,591	322,321,908	132,738	33,514	0.0725
42	Total Unbilled Rev.(See Instr. 6)	38,950	2,271,205	0	0	0.0583
43	TOTAL	4,487,541	324,593,113	132,738	33,808	0.0723

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	521,720	35,187,637	560	931,643	0.0674
4						
5	Outdoor Lighting - Energy Only					
6	11.03	1,987	153,956	252	7,885	0.0775
7				-252		
8	Outdoor Lighting					
9	11.04	14,421	1,802,260	258	55,895	0.1250
10				-258		
11	Standby Service - Option A Firm					
12	11.01	139	15,035	5	27,800	0.1082
13						
14	Small Power Producer Rider					
15	12.01		680	19		
16				-19		
17	Conservation Imp Prog Rev		-1,192,666			
18	ND Big Stone Plant II Recvy		-30,853			
19	Environmental Rider Rev		1,480,431			
20	Transmission Cost Recvy		883,532			
21	Renewable Resource Rider		-1,318,440			
22	Fuel Clause Adjustment Rec		-703,813			
23	MN Rate Case Rev Reduction		-209,124			
24						
25	SUBTOTAL Billed	3,016,655	203,540,237	28,588	105,522	0.0675
26	Unbilled Rev (See Instr. 6)	25,417	1,422,939			0.0560
27	TOTAL - 442	3,042,072	204,963,176	28,588	106,411	0.0674
28						
29						
30						
31	Column D Lines 6,9 & 15					
32	customers are also served under					
33	other commerical service.					
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,448,591	322,321,908	132,738	33,514	0.0725
42	Total Unbilled Rev.(See Instr. 6)	38,950	2,271,205	0	0	0.0583
43	TOTAL	4,487,541	324,593,113	132,738	33,808	0.0723

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	7,205	542,550	253	28,478	0.0753
4				-253		
5	Outdoor lighting					
6	11.04	18,775	2,875,629	354	53,037	0.1532
7						
8	Conservation Imp Prog Rev		-8,480			
9	ND Big Stone Plant II Recvy		-85			
10	Environmental Rider Rev		15,761			
11	Transmission Cost Recvy		7,761			
12	Renewable Resource Rider		-9,202			
13	Fuel Clause Adjustment Rec		-5,239			
14	MN Rate Case Rev Reduction		-1,490			
15						
16	Subtotal billed	25,980	3,417,205	354	73,390	0.1315
17	Unbilled Revenue	82	10,272			0.1253
18	TOTAL - 444	26,062	3,427,477	354	73,621	0.1315
19						
20	Other Public Authority-445					
21	Pumping and Sirens					
22	11.05,11.06	40,229	2,756,639	1,291	31,161	0.0685
23	Conservation Imp Prog Rev		-14,229			
24	ND Big Stone Plant II Recvy		-106			
25	Environmental Rider Rev		21,142			
26	Transmission Cost Recvy		10,831			
27	Renewable Resource Rider		-13,651			
28	Fuel Clause Adjustment Rec		-8,462			
29	MN Rate Case Rev Reduction		-2,510			
30						
31	Unbilled Revenue	319	18,553			0.0582
32	TOTAL - 445	40,548	2,768,207	1,291	31,408	0.0683
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	4,448,591	322,321,908	132,738	33,514	0.0725
42	Total Unbilled Rev.(See Instr. 6)	38,950	2,271,205	0	0	0.0583
43	TOTAL	4,487,541	324,593,113	132,738	33,808	0.0723

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) 12/31/2013	2013/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	\$ 638,868
9.02	Residential service (control demand)	(70,902)
14.01	Water heating - controlled (off peak)	64,084
14.04,14.05,14.06,14.07	Controlled service	(8,857)
14.07	Fixed time of delivery service	5,865
11.03	Outdoor lighting - energy only	(192)
11.04	Outdoor lighting	<u>1,933</u>
Total Residential		630,799

Commercial and industrial - 442

10.01,10.02	General service	133,545
9.03	Farm service	59,153
10.03	Large general service	(2,641,524)
14.02	Real time pricing rider	0
10.05	Large general service (time of day)	1,104,907
14.03	Large general service rider	7,745
14.01	Water heating - controlled (off-peak)	7,575
14.04,14.05,14.06,14.07	Controlled service	(16,995)
14.07	Fixed time of delivery service	22,062
11.02	Irrigation service	1,444
10.04	Commercial time of use	3,573,708
11.03	Outdoor lighting - energy only	1,870
11.04	Outdoor lighting	(4,584)
11.01	Standby service-option A firm	<u>(666)</u>
Total commercial and industrial		2,248,240

Streetlighting - 444

11.03	Outdoor lighting - energy only	6,892
11.04	Outdoor lighting	<u>2,832</u>
Total streetlighting		9,724

Other public authority - 445

11.05,11.06	Pumping and sirens	<u>25,494</u>
TOTAL		\$ 2,914,257 =====

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	0.073	NA	NA
3	Newfolden, MN	RQ	174	0.530	NA	NA
4	Nielsville, MN	RQ	175	0.043	NA	NA
5	Shelly, MN	RQ	176	0.154	NA	NA
6						
7						
8	NON-RQ SALES					
9	Cargill Power Markets, LLC	OS	V9	NA	NA	NA
10	DTE Energy Trading, Inc.	OS	V9	NA	NA	NA
11	EDF Trading North America	OS	V9	NA	NA	NA
12	Horizon Wind Energy LLC	OS	V9	NA	NA	NA
13	Minnesota Power	OS	V9	NA	NA	NA
14	MacQuarie Energy LLC	OS	V9	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)

demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
					1
241	3,894	9,379	2,449	15,722	2
2,478	29,872	83,728	23,904	137,504	3
108	2,926	3,750	1,037	7,713	4
777	11,201	27,315	7,790	46,306	5
					6
					7
					8
2,400		866		866	9
800		-1,065		-1,065	10
33,650		135,268		135,268	11
		-144		-144	12
40,400		1,005,287		1,005,287	13
800		-2,142		-2,142	14
3,604	47,893	124,172	35,180	207,245	
1,728,606	0	14,638,811	0	14,638,811	
1,732,210	47,893	14,762,983	35,180	14,846,056	

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)		
19,600		418,119		418,119	1
84,800		65,390		65,390	2
84,815		6,461		6,461	3
2,400		-16,819		-16,819	4
110,400		3,256,800		3,256,800	5
800		23,200		23,200	6
704		31,296		31,296	7
770,950		-845,856		-845,856	8
576,525		14,638,812		14,638,812	9
					10
-438		-4,076,662		-4,076,662	11
					12
					13
					14
3,604	47,893	124,172	35,180	207,245	
1,728,606	0	14,638,811	0	14,638,811	
1,732,210	47,893	14,762,983	35,180	14,846,056	

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

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

Lines 2 - 5 are fuel adjustment charges.

Schedule Page: 310.1 Line No.: 11 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 and losses in accounts 421 and 426.5, as appropriate. This amount represents the non-asset based cost of forward energy sales.

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,718,195	1,826,859
5	(501) Fuel	69,634,963	64,141,238
6	(502) Steam Expenses	3,115,567	2,914,839
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,689,109	2,576,896
10	(506) Miscellaneous Steam Power Expenses	4,669,710	4,375,501
11	(507) Rents	535	1,500
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	81,828,079	75,836,833
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	758,277	816,833
16	(511) Maintenance of Structures	770,212	717,803
17	(512) Maintenance of Boiler Plant	6,172,350	6,655,306
18	(513) Maintenance of Electric Plant	1,139,056	1,390,201
19	(514) Maintenance of Miscellaneous Steam Plant	1,037,412	1,113,359
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	9,877,307	10,693,502
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	91,705,386	86,530,335
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	17,437	37,235
45	(536) Water for Power		
46	(537) Hydraulic Expenses	18,548	20,438
47	(538) Electric Expenses	99,185	97,790
48	(539) Miscellaneous Hydraulic Power Generation Expenses	37,330	22,504
49	(540) Rents		54
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	172,500	178,021
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	3,187	2,907
54	(542) Maintenance of Structures	9,994	3,651
55	(543) Maintenance of Reservoirs, Dams, and Waterways	220,302	281,218
56	(544) Maintenance of Electric Plant	27,164	8,740
57	(545) Maintenance of Miscellaneous Hydraulic Plant		319
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	260,647	296,835
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	433,147	474,856

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	177,535	193,199
63	(547) Fuel	2,139,681	2,536,985
64	(548) Generation Expenses	2,392,405	2,598,726
65	(549) Miscellaneous Other Power Generation Expenses	558,504	668,907
66	(550) Rents	562,117	547,607
67	TOTAL Operation (Enter Total of lines 62 thru 66)	5,830,242	6,545,424
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	40,779	37,417
70	(552) Maintenance of Structures	39,732	65,537
71	(553) Maintenance of Generating and Electric Plant	692,029	537,672
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	57,897	22,475
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	830,437	663,101
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	6,660,679	7,208,525
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	52,005,874	49,183,767
77	(556) System Control and Load Dispatching	450,910	425,618
78	(557) Other Expenses	516,418	763,728
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	52,973,202	50,373,113
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	151,772,414	144,586,829
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	394,683	410,161
84			
85	(561.1) Load Dispatch-Reliability	75,910	76,149
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,542,773	2,380,398
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	501,506	602,731
90	(561.6) Transmission Service Studies	3,843	584
91	(561.7) Generation Interconnection Studies	133	
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	264,874	303,936
94	(563) Overhead Lines Expenses	256,921	536,080
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	9,892,519	5,745,570
97	(566) Miscellaneous Transmission Expenses	1,333,634	1,363,146
98	(567) Rents	57,166	43,141
99	TOTAL Operation (Enter Total of lines 83 thru 98)	15,323,962	11,461,896
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	177,027	192,590
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	116,690	97,269
104	(569.2) Maintenance of Computer Software	693,596	586,489
105	(569.3) Maintenance of Communication Equipment	114,946	101,234
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,096,529	1,126,813
108	(571) Maintenance of Overhead Lines	1,762,918	1,836,227
109	(572) Maintenance of Underground Lines	360	216
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,962,066	3,940,838
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	19,286,028	15,402,734

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation	1,126,719	1,278,103
117	(575.3) Transmission Rights Market Facilitation	277,392	272,907
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,404,111	1,551,010
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software	355,415	317,233
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)	355,415	317,233
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	1,759,526	1,868,243
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	391,934	359,230
135	(581) Load Dispatching	279,325	257,567
136	(582) Station Expenses	221,746	212,466
137	(583) Overhead Line Expenses	309,683	309,255
138	(584) Underground Line Expenses	1,697,393	1,796,915
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	906,678	942,543
141	(587) Customer Installations Expenses	191,354	237,199
142	(588) Miscellaneous Expenses	2,911,754	2,931,874
143	(589) Rents	238,522	249,928
144	TOTAL Operation (Enter Total of lines 134 thru 143)	7,148,389	7,296,977
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	906,855	745,955
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	998,178	858,855
149	(593) Maintenance of Overhead Lines	4,539,291	3,892,582
150	(594) Maintenance of Underground Lines	1,116,096	1,051,040
151	(595) Maintenance of Line Transformers	59,066	78,494
152	(596) Maintenance of Street Lighting and Signal Systems	1,082,338	1,104,796
153	(597) Maintenance of Meters	744,889	740,152
154	(598) Maintenance of Miscellaneous Distribution Plant	103,584	99,305
155	TOTAL Maintenance (Total of lines 146 thru 154)	9,550,297	8,571,179
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	16,698,686	15,868,156
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	131,373	124,006
160	(902) Meter Reading Expenses	6,059,234	5,594,019
161	(903) Customer Records and Collection Expenses	6,141,525	5,857,780
162	(904) Uncollectible Accounts	760,000	598,000
163	(905) Miscellaneous Customer Accounts Expenses	330,156	328,188
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	13,422,288	12,501,993

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	751,283	658,971
168	(908) Customer Assistance Expenses	6,929,006	6,668,556
169	(909) Informational and Instructional Expenses	390,446	406,804
170	(910) Miscellaneous Customer Service and Informational Expenses	61,032	83,963
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	8,131,767	7,818,294
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	324,835	251,430
176	(913) Advertising Expenses	517	16,158
177	(916) Miscellaneous Sales Expenses	297,971	273,779
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	623,323	541,367
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	20,664,050	18,693,578
182	(921) Office Supplies and Expenses	6,856,713	4,536,852
183	(Less) (922) Administrative Expenses Transferred-Credit	1,765,173	1,752,389
184	(923) Outside Services Employed	1,218,312	1,050,131
185	(924) Property Insurance	1,842,172	2,155,325
186	(925) Injuries and Damages	2,027,359	1,441,111
187	(926) Employee Pensions and Benefits	3,027,596	2,218,402
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	1,087,449	855,803
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	361,179	364,304
192	(930.2) Miscellaneous General Expenses	1,341,268	693,835
193	(931) Rents	284,005	237,150
194	TOTAL Operation (Enter Total of lines 181 thru 193)	36,944,930	30,494,102
195	Maintenance		
196	(935) Maintenance of General Plant	2,578,021	1,793,879
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	39,522,951	32,287,981
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	251,216,983	230,875,597

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) 12/31/2013	Year/Period of Report 2013/Q4
FOOTNOTE DATA			

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

\$713,545 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

\$552,845 of the year-to-date expense recorded in Accounts 561 and 569 is designated as Account 561.BA expense.

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Cargill Power Markets	OS		NA	NA	NA
2	EDF Trading North America	OS		NA	NA	NA
3	Great River Energy	SF		50	NA	NA
4	Horizon Wind Energy LLC	OS		NA	NA	NA
5	MacQuarie Energy LLC	OS		NA	NA	NA
6	Minnkota Power Cooperative	OS		NA	NA	NA
7	NextEra Energy Power Marketing	OS		NA	NA	NA
8	Northern States Power Company	OS		NA	NA	NA
9	Southern MN Municipal Power Agency	SF		75	NA	NA
10	Western Area Power Administration	OS		NA	NA	NA
11	Western Area Power Administration WEC	OS		NA	NA	NA
12	WE Energies	SF		50	NA	NA
13	Willmar Municipal Utilities	OS		NA	NA	NA
14	Beltrami Electric Cooperative	RQ		NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Nodak Rural Electric Cooperative	RQ		NA	NA	NA
2	P K M Electric Cooperative	RQ		NA	NA	NA
3	Red Lake Rural Electric Cooperative	RQ		NA	NA	NA
4	Lake Region Rural Electric Cooperative	RQ		NA	NA	NA
5	Cass County Electric Cooperative	RQ		NA	NA	NA
6	Lyon Lincoln Electric Cooperative	RQ		NA	NA	NA
7	Prairie Lakes Muni Waste	RQ		NA	NA	NA
8	Dakota Magic Casino	RQ		NA	NA	NA
9	State Auto Insurance	RQ		NA	NA	NA
10	Kindred School	RQ		NA	NA	NA
11	Valley Queen Cheese	OS		NA	NA	NA
12	Stevens Community Medical	OS		NA	NA	NA
13	City of Detroit Lakes	OS		NA	NA	NA
14	American Crystal Sugar	OS		NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Energy Mtce Service - Broadband Srvcs	OS		NA	NA	NA
2	Dakota Wind Exchange	OS		NA	NA	NA
3	Hendricks Wind I	OS		NA	NA	NA
4	Borderline Wind	OS		NA	NA	NA
5	Univ. of MN - Morris	OS		NA	NA	NA
6	FPL Energy ND II, LLC	OS		NA	NA	NA
7	Langdon Wind, LLC	OS		NA	NA	NA
8	Langdon Wind, LLC - Curtailment	OS		NA	NA	NA
9	Turtle Mountain Community College	OS		NA	NA	NA
10	District 45 Methane	OS		NA	NA	NA
11	LacQui Parle School	OS		NA	NA	NA
12	Pembina Border Station	OS		NA	NA	NA
13	Lake Region State College	OS		NA	NA	NA
14	Ashtabula Wind III LLC	OS		NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	MN Co Generation	OS		NA	NA	NA
2	ND Co Generation	OS		NA	NA	NA
3	SD Co Generation	OS		NA	NA	NA
4	Excel Energy Under Reported Load Adj.	OS		NA	NA	NA
5	RBC Capital Markets Corporation	OS		NA	NA	NA
6	Midwest ISO Energy Market	OS		NA	NA	NA
7						
8						
9						
10						
11						
12	Non-Asset Based Cost of Sales					
13	Miscellaneous Energy Market Changes					
14	Other ISO Energy Markets					
	Total					

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
2,400				3,031		3,031	1
144,000				-178,137		-178,137	2
			740,000			740,000	3
				107		107	4
50				-119		-119	5
203,600				-1,293,513		-1,293,513	6
84,800				-197,786		-197,786	7
404,015				6,913,226		6,913,226	8
			-196,875			-196,875	9
					50,610	50,610	10
29,870				993,192		993,192	11
			250,000			250,000	12
400				14,640		14,640	13
55,361			549,717	2,598,571	93,228	3,241,516	14
2,968,042			1,614,319	50,247,717	143,838	52,005,874	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.

5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.

7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.

8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.

9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
2,910			46,691	151,759		198,450	1
3,597			44,661	165,849		210,510	2
3,001			40,649	134,801		175,450	3
			633			633	4
			4,989			4,989	5
14				1,606		1,606	6
			18,480			18,480	7
			37,400			37,400	8
			2,520			2,520	9
			33,220			33,220	10
			19,370			19,370	11
			21,600			21,600	12
1,021			1,264	1,531		2,795	13
16				156		156	14
2,968,042			1,614,319	50,247,717	143,838	52,005,874	

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)	
39				1,232		1,232	1
79				2,514		2,514	2
2,377				106,975		106,975	3
2,032				60,953		60,953	4
4,755				261,551		261,551	5
43,654				1,305,244		1,305,244	6
71,769				2,814,801		2,814,801	7
200				15,604		15,604	8
573				18,978		18,978	9
9,295				405,268		405,268	10
36				1,146		1,146	11
167				5,372		5,372	12
3,162				98,618		98,618	13
60,784				1,608,348		1,608,348	14
2,968,042			1,614,319	50,247,717	143,838	52,005,874	

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)	
124				10,651		10,651	1
68				414		414	2
41				1,223		1,223	3
-9,667				-166,885		-166,885	4
650,200				44,271		44,271	5
1,358,353				49,715,395		49,715,395	6
							7
							8
							9
							10
							11
-165,054				-15,490,430		-15,490,430	12
				-13,517		-13,517	13
				131,077		131,077	14
2,968,042			1,614,319	50,247,717	143,838	52,005,874	

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) 12/31/2013	Year/Period of Report 2013/Q4
FOOTNOTE DATA			

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

January through December 2013

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

June - December 2013

Schedule Page: 326 Line No.: 10 Column: I

Load Following charge

Schedule Page: 326 Line No.: 12 Column: a

January - May 2013

Schedule Page: 326 Line No.: 14 Column: I

Nomination charge

Schedule Page: 326.3 Line No.: 12 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				
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
4	(1)	Badger, SD		1,609	1,540	1
4	(1)	Newfolden, MN		2,882	2,693	2
4	(1)	Nielsville, MN		699	653	3
4	(1)	Shelly, MN		1,856	1,735	4
4	(1)	Fort Totten, ND		288	272	5
4	(1)	Grafton, ND		4,835	4,561	6
4	(1)	Devils Lake, ND		556	520	7
4	(1)	Bottineau, ND		1,118	1,045	8
4	(1)	Wahpeton, ND		8,735	8,202	9
4	(1)	Belcourt, ND		2,392	2,257	10
4	(1)	Oakes, ND		59	56	11
See Footnote	(1)	Various Interconnect		230,901	215,795	12
		(1)		13,220		13
		(1)		-12,761		14
		(1)		-3,661		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	252,728	239,329	

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
9,628			9,628	1
25,936			25,936	2
8,010			8,010	3
17,139			17,139	4
1,468			1,468	5
24,243			24,243	6
5,956			5,956	7
11,100			11,100	8
92,837			92,837	9
31,288			31,288	10
1,630			1,630	11
	215,795		215,795	12
				13
				14
				15
		15,779,415	15,779,415	16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
229,235	215,795	15,779,415	16,224,445	

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) 12/31/2013	2013/Q4
FOOTNOTE DATA			

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

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

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

Various companies

Miscellaneous losses - mwh received

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

Midwest Independent System Operator Transmission

Schedule 1 Network = \$408,540.92

Schedule 1 Firm = \$ 48,986.52

Schedule 1 Non-firm = \$ 17,102.69

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 in column f, lines 1-12 and column g, lines 13-15.

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					2,501,080	2,501,080
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						2,501,080	2,501,080

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) 12/31/2013	Year/Period of Report 2013/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 2013.

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2013

Year/Period of Report
End of 2013/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	229,210
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	22,838
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	184,373
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	27,275
6	Director Fees & Expenses	609,055
7	Misc. Labor Not Provided for Elsewhere	253,737
8	News Release Distribution - Sundog Interactive, Inc.	14,780
9		
10		
11		
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41		
42		
43		
44		
45		
46	TOTAL	1,341,268

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

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			810,698		810,698
2	Steam Production Plant	9,734,970	7,877			9,742,847
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	358,433				358,433
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	11,497,398	46,768			11,544,166
7	Transmission Plant	5,271,417				5,271,417
8	Distribution Plant	10,942,847				10,942,847
9	Regional Transmission and Market Operation					
10	General Plant	2,890,820				2,890,820
11	Common Plant-Electric					
12	TOTAL	40,695,885	54,645	810,698		41,561,228

B. Basis for Amortization Charges

The \$810,698 is amortization of:

Franchises and Consents (302)

\$41,845 for hydro plant licenses with a remaining life of 8.92 years at a 3.21% rate.

Miscellaneous Intangible Plant (303)

\$768,852 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	4,450		-8.80	1.87	SQ	15.18
15	312	33,318		-8.80	3.41	SQ	15.19
16	314	10,936		-8.80	3.23	SQ	15.19
17	315	2,872		-8.80	2.63	SQ	15.18
18	316	989		-8.60	3.08	SQ	15.19
19							
20							
21	Steam Production -						
22	Hoot Lake Plant						
23	311 - Units 2, 3	607		-11.20	2.04	SQ	10.35
24	312 - Units 2, 3	11,665		-11.20	4.29	SQ	10.36
25	314 - Units 2, 3	1,362		-11.20	2.31	SQ	10.35
26	315 - Units 2, 3	80		-11.20	1.41	SQ	10.35
27	316 - Units 2, 3	364		-11.10	4.45	SQ	10.36
28							
29							
30	Steam Production -						
31	Coyote Plant						
32	311	10,776		-5.00	1.89	SQ	19.93
33	312	33,363		-5.00	2.10	SQ	19.94
34	314	12,231		-5.00	2.95	SQ	19.95
35	315	4,665		-5.00	2.22	SQ	19.95
36	316	930		-4.70	2.77	SQ	19.95
37	STEAM PRODUCTION						
38	SUBTOTAL	128,608					
39							
40	Hydro Production -						
41	Hoot Lake Hydro						
42	331	2			0.24	SQ	9.37
43	332	111			3.41	SQ	9.37
44	333	14			1.44	SQ	9.38
45	334	6			1.99	SQ	9.38
46							
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	Hydro Production -						
13	Wright Hydro						
14	331	5			3.00	SQ	9.38
15	332	172			4.80	SQ	9.38
16	333	105			4.89	SQ	9.38
17	334	97			5.15	SQ	9.39
18	335	88			8.15	SQ	9.38
19							
20							
21	Hydro Production -						
22	Pisgah Hydro						
23	331	3			2.39	SQ	9.38
24	332	229			7.15	SQ	9.39
25	333	100			6.66	SQ	9.39
26	334	53			5.71	SQ	9.38
27	335	69			11.85	SQ	9.38
28							
29							
30	Hydro Production -						
31	Dayton Hollow Hydro						
32	331	16			10.48	SQ	9.38
33	332	708			9.24	SQ	9.39
34	333	140			6.56	SQ	9.39
35	334	83			4.57	SQ	9.38
36	335	114			10.92	SQ	9.38
37							
38							
39	Hydro Production -						
40	Taplin Gorge Hydro						
41	331	3			0.91	SQ	9.36
42	332	351			6.22	SQ	9.38
43	333	1			0.79	SQ	9.36
44	334	22			4.00	SQ	9.38
45	335	84			8.63	SQ	9.38
46							
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	Hydro Production -						
13	Bemidji Hydro						
14	331	147			7.82	SQ	9.39
15	332	460			7.44	SQ	9.38
16	333	176			5.80	SQ	9.38
17	334	3			5.79	SQ	9.37
18	335	1			9.68	SQ	9.39
19	HYDRO PRODUCTION						
20	SUBTOTAL	3,363					
21							
22	Other Production -						
23	Jamestown Peaking #1						
24	341	57		-0.60	2.34	SQ	10.35
25	342	244		-0.60	5.78	SQ	10.35
26	343	710		-0.60	2.44	SQ	10.35
27	345	55		-0.60	3.48	SQ	10.35
28	346	40		-0.60	4.79	SQ	10.36
29							
30							
31	Other Production -						
32	Lake Preston Peaking						
33	341	39		-0.90	1.91	SQ	10.35
34	342	110		-0.90	3.31	SQ	10.36
35	343	529		-0.90	1.70	SQ	10.35
36	345	52		-0.90	1.45	SQ	10.35
37	346	3		-0.90	1.46	SQ	10.35
38							
39							
40	Other Production -						
41	Jamestown Peaking #2						
42	341	15		-0.60	5.82	SQ	10.36
43	342	9		-0.60	2.49	SQ	10.35
44	343	699		-0.60	1.84	SQ	10.35
45	345	42		-0.60	6.00	SQ	10.36
46	346	5		-0.60	1.85	SQ	10.35
47							
48	Other Production -						
49	Fergus Falls Cont. Ctr						
50	343	307			2.88	SQ	18.05

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	Other Production -						
13	Solway Combustion Turb						
14	341	3,059		-0.10	2.81	SQ	25.60
15	342	724		-0.10	2.82	SQ	25.60
16	343	15,227		-0.10	2.81	SQ	25.60
17	345	896		-0.10	2.80	SQ	25.60
18	346	231		-0.10	2.90	SQ	25.61
19							
20							
21	Other Production -						
22	Langdon Wind Energy						
23	341	1,997			3.92	S5	20.50
24	344	55,853			3.95	S5	20.54
25	345	5,680			3.93	S5	20.57
26	Ashtabula Wind Energy						
27	341	2,729			3.91	S5	21.50
28	344	89,338			3.90	S5	21.51
29	345	5,243			3.91	S5	21.50
30	Luverne Wind Energy						
31	341	1,975			3.87	S5	22.50
32	344	57,018			3.89	S5	22.51
33	345	4,271			3.88	S5	22.50
34							
35	OTHER PRODUCTION						
36	SUBTOTAL	247,157					
37							
38	Transmission Plant						
39	353	57,006	45.00	-5.00	1.65	R0.5	49.09
40	354	2,267	55.00	-10.00	1.50	R5	38.90
41	355	60,513	55.00	-50.00	2.30	S1.5	47.58
42	356	44,412	55.00	-30.00	2.06	S1.5	42.29
43	358	10	40.00	-5.00	2.12	S4	8.34
44	SUBTOTAL	164,208					
45							
46							
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	Distribution Plant						
13	362	49,073	35.00	5.00	2.36	S-5	28.76
14	364	29,709	60.00	-75.00	2.63	R3	46.01
15	365	10,909	58.00	-100.00	3.19	R3	38.74
16	367	33,349	35.00	-5.00	2.82	R4	20.53
17	368	64,436	40.00	50.00	1.45	R0.5	24.23
18	369	-1,221	48.00	-150.00	4.77	S5	29.33
19	369.1	21,150	40.00	-20.00	2.58	R4	31.19
20	370	14,378	33.00		2.95	S0.5	22.00
21	370.1	4,371	20.00		5.75	L3	8.58
22	370.2	138	5.00		20.00	SQ-Amortized	1.70
23	371.2	3,128	19.00	10.00	4.05	L0	16.22
24	373	2,279	16.00	-5.00	5.16	L2	10.28
25							
26							
27	SUBTOTAL	231,699					
28							
29	General Plant -						
30	390	14,618	45.00	10.00	1.81	L1	36.38
31	390.1	3,250		-5.00	3.53	SQ	18.05
32	390.2	338		-5.00	3.50	SQ	13.26
33	390.3	1,907		-5.00	2.37	SQ	22.75
34	391	551	15.00		6.67	SQ-Amortized	5.23
35	391.1	505	10.00		10.00	SQ-Amortized	5.02
36	391.2	219	10.00		10.00	SQ-Amortized	4.00
37	391.5	2,051	5.00		20.00	SQ-Amortized	2.74
38	391.6	771	5.00		20.00	SQ-Amortized	1.87
39	392	13,242					
40	Aircraft		7.00	39.00			
41	Autos		5.00	15.00			
42	Light Trucks		10.00	10.00			
43	Heavy Trucks & Semi		10.00	15.00			
44	Tractors-incl. cranes		10.00	15.00			
45	Trailers		15.00	10.00			
46	Portable Oil Purifier		10.00	20.00			
47	Trenchers		10.00	10.00			
48	Misc. Light Equipment		10.00	10.00			
49	Misc. Heavy Equipment		15.00	15.00			
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	394	2,012	15.00		6.67	SQ-Amortized	9.26
13	394.2	368	15.00		6.67	SQ-Amortized	10.47
14	395		15.00		6.67	SQ-Amortized	1.00
15	396	358	15.00	5.00	3.44	L0	16.33
16	397	392	15.00		6.67	SQ-Amortized	9.86
17	397.1	792	10.00		10.00	SQ-Amortized	6.56
18	397.2	1,768	15.00		6.67	SQ-Amortized	8.00
19	397.3	301	10.00		10.00	SQ-Amortized	3.39
20	394.4	974	25.00	5.00	3.29	R4	15.98
21	SUBTOTAL	44,417					
22	TOTAL	819,452					
23	SUBACCOUNTS USED						
24							
25							
26							
27							
28							
29							
30							
31							
32							
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34							
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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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

Schedule Page: 336.5 Line No.: 23 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
- 290.3 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 Communications 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	304,932		304,932	
3					
4	SD Public Utilities Commission	40,924		40,924	
5					
6	ND Public Service Commission	6,942		6,942	
7					
8	Federal Energy Regulatory Commission	281,305		281,305	
9					
10	Other Expenses:				
11	MN Public Utilities Commission:				
12	MN Rate Case (E017/GR-10-239) Amort 3 yrs				206,280
13	Resource Plan (E017/RP-10-623)		25,036	25,036	
14	Miscellaneous		209,962	209,962	
15					
16	ND Public Service Commission:				
17	ND CRR AQCS (PU-13-84, PU-13-79)		40,080	40,080	
18	Miscellaneous		22,923	22,923	
19					
20	SD Public Utilities Commission:				
21	SD Rate Case (EL-10-011) Amort 3 yrs				78,889
22	Miscellaneous		46,308	46,308	
23					
24	FERC				
25	Miscellaneous		109,037	109,037	
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	634,103	453,346	1,087,449	285,169

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				Line No.
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	
Department (f)	Account No. (g)	Amount (h)					
							1
Electric	928	304,932					2
							3
Electric	928	40,924					4
							5
Electric	928	6,942					6
							7
Electric	928	281,305					8
							9
							10
							11
Electric	928				206,280		12
Electric	928	25,036					13
Electric	928	209,962					14
							15
							16
Electric	928	40,080					17
Electric	928	22,923					18
							19
							20
Electric	928				72,820	6,069	21
Electric	928	46,308					22
							23
							24
Electric	928	109,037					25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		1,087,449			279,100	6,069	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	Distribution	Miscellaneous
5	Other	Miscellaneous
6	Other	Miscellaneous
7		
8	Sub-Total Performed Internally	
9		
10	PERFORMED EXTERNALLY:	
11		Chartwell Inc
12		E Source Inc
13		
14		
15		
16		
17	Sub-Total Performed Externally	
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34	SUM OF ABOVE	
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
1,208		588	1,208		4
16,767		920	16,767		5
20,151		930.2	20,151		6
					7
38,126			38,126		8
					9
					10
	7,617	930.2	7,617		11
	13,758	930.2	13,758		12
					13
					14
					15
					16
	21,375		21,375		17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
38,126	21,375		59,501		34
					35
					36
					37
					38

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminating and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	70,473,991		70,473,991
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	13,387,140		13,387,140
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	13,387,140		13,387,140
72	Plant Removal (By Utility Departments)			
73	Electric Plant	3,641		3,641
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	3,641		3,641
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock (151)	50,970		50,970
79	Miscellaneous Deferred Debits (186)	1,332,417		1,332,417
80	Other Electric Revenue (456)	897,849		897,849
81	Expenses of Nonutility Operations (417.1)	248,840		248,840
82	Exp. for Certain Civic, Political and Related Activity (426.4)	131,939		131,939
83	Other Deductions (426.5)	63,481		63,481
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	2,725,496		2,725,496
96	TOTAL SALARIES AND WAGES	86,590,268		86,590,268

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) 12/31/2013	Year/Period of Report 2013/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) 12/31/2013	Year/Period of Report End of <u>2013/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)
12/31/2013

Year/Period of Report
End of 2013/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8	Not available.				
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
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28					
29					
30					
31					
32					
33					
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				9,228,971	\$/MW-Hr	906,635
2	Reactive Supply and Voltage				4,063,887	\$/MW-Hr	607,434
3	Regulation and Frequency Response	49,375	\$/MW-Hr	35,056			
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)	49,375		35,056	13,292,858		1,514,069

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) 12/31/2013	Year/Period of Report 2013/Q4
FOOTNOTE DATA			

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

Line 1 does not include \$15,554 of services purchased from WAPA which was purchased with a "Unit of Measure" of \$/Schedule-Day.

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	797	22	12	796	1				
2	February	781	1	11	780	1				
3	March	739	20	8	738	1				
4	Total for Quarter 1	2,317			2,314	3				
5	April	667	9	10	666	1				
6	May	567	3	9	566	1				
7	June	618	25	16	617	1				
8	Total for Quarter 2	1,852			1,849	3				
9	July	659	16	15	658	1				
10	August	688	27	15	687	1				
11	September	659	6	14	658	1				
12	Total for Quarter 3	2,006			2,003	3				
13	October	691	28	9	690	1				
14	November	761	22	9	760	1				
15	December	823	9	11	822	1				
16	Total for Quarter 4	2,275			2,272	3				
17	Total Year to Date/Year	8,450			8,438	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) 12/31/2013	Year/Period of Report 2013/Q4
FOOTNOTE DATA			

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

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

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

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

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: Not applicable

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

Name of Respondent
Otter Tail Power Company

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

Date of Report
(Mo, Da, Yr)
12/31/2013

Year/Period of Report
End of 2013/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)	4,487,541
3	Steam	3,204,582	23	Requirements Sales for Resale (See instruction 4, page 311.)	3,604
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,728,606
5	Hydro-Conventional	18,619	25	Energy Furnished Without Charge	4
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	13,276
7	Other	495,721	27	Total Energy Losses	467,332
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	6,700,363
9	Net Generation (Enter Total of lines 3 through 8)	3,718,922			
10	Purchases	2,968,042			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	252,728			
17	Delivered	239,329			
18	Net Transmission for Other (Line 16 minus line 17)	13,399			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	6,700,363			

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) 12/31/2013	Year/Period of Report End of <u>2013/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	721,636	182,581	797	22	1200
30	February	639,849	137,347	781	1	1100
31	March	660,914	224,800	739	20	800
32	April	653,410	287,140	667	9	1000
33	May	439,422	84,943	567	3	900
34	June	429,031	99,773	618	25	1600
35	July	510,886	140,171	659	16	1500
36	August	479,657	113,565	688	27	1500
37	September	431,312	101,576	659	6	1400
38	October	446,276	86,761	691	28	900
39	November	516,691	87,623	761	22	900
40	December	771,279	182,326	823	9	1100
41	TOTAL	6,700,363	1,728,606			

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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
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)	150	257
7	Plant Hours Connected to Load	7064	7757
8	Net Continuous Plant Capability (Megawatts)	149	257
9	When Not Limited by Condenser Water	149	257
10	When Limited by Condenser Water	149	257
11	Average Number of Employees	80	74
12	Net Generation, Exclusive of Plant Use - KWh	881972839	1513249905
13	Cost of Plant: Land and Land Rights	718662	374603
14	Structures and Improvements	33091411	22787501
15	Equipment Costs	128183048	117966869
16	Asset Retirement Costs	101890	62122
17	Total Cost	162095011	141191095
18	Cost per KW of Installed Capacity (line 17/5) Including	1118.6681	632.7183
19	Production Expenses: Oper, Supv, & Engr	659992	673400
20	Fuel	15360813	30444700
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	1629635	608269
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	707943	977060
26	Misc Steam (or Nuclear) Power Expenses	588320	2348652
27	Rents	438	97
28	Allowances	0	0
29	Maintenance Supervision and Engineering	245557	374644
30	Maintenance of Structures	345581	346492
31	Maintenance of Boiler (or reactor) Plant	2190831	2421434
32	Maintenance of Electric Plant	396212	571126
33	Maintenance of Misc Steam (or Nuclear) Plant	351256	400134
34	Total Production Expenses	22476578	39166008
35	Expenses per Net KWh	0.0255	0.0259
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels
38	Quantity (Units) of Fuel Burned	705083	2974
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	6988	140000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	22.253	134.148
41	Average Cost of Fuel per Unit Burned	22.143	133.980
42	Average Cost of Fuel Burned per Million BTU	1.584	22.786
43	Average Cost of Fuel Burned per KWh Net Gen	0.010	0.000
44	Average BTU per KWh Net Generation	11158.000	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: <i>Solway</i> (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas Turbine	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	
3	Year Originally Constructed	2003	
4	Year Last Unit was Installed	2003	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	44.50	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	49	0
7	Plant Hours Connected to Load	1455	0
8	Net Continuous Plant Capability (Megawatts)	42	0
9	When Not Limited by Condenser Water	42	0
10	When Limited by Condenser Water	42	0
11	Average Number of Employees	2	0
12	Net Generation, Exclusive of Plant Use - KWh	42778182	0
13	Cost of Plant: Land and Land Rights	89809	0
14	Structures and Improvements	4277574	0
15	Equipment Costs	23860826	0
16	Asset Retirement Costs	0	0
17	Total Cost	28228209	0
18	Cost per KW of Installed Capacity (line 17/5) Including	634.3418	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	1344766	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	457257	0
26	Misc Steam (or Nuclear) Power Expenses	84884	0
27	Rents	13507	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	5906	0
30	Maintenance of Structures	14897	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	359817	0
33	Maintenance of Misc Steam (or Nuclear) Plant	42330	0
34	Total Production Expenses	2323364	0
35	Expenses per Net KWh	0.0543	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	467835	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	472500	140000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.179	0.000
41	Average Cost of Fuel per Unit Burned	4.184	0.000
42	Average Cost of Fuel Burned per Million BTU	4.184	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.031	0.000
44	Average BTU per KWh Net Generation	10936.000	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
	138			42			21		6
	16801			25			23		7
	149			41			18		8
	149			41			18		9
	149			41			18		10
	38			1			0		11
	809359300			273767			93524		12
	617367			24614			12339		13
	6116976			305657			229834		14
	49833346			7359869			3891658		15
	130498			0			0		16
	56698187			7690140			4133831		17
	441.2310			159.8449			171.5283		18
	416928			331			0		19
	18965450			97483			79203		20
	0			0			0		21
	957558			0			0		22
	0			0			0		23
	0			0			0		24
	1137980			48007			19131		25
	1276795			7592			50		26
	0			43			0		27
	0			0			0		28
	194627			4257			2135		29
	152334			23736			220		30
	1669802			0			0		31
	222057			127461			72052		32
	329291			144			850		33
	25322822			309054			173641		34
	0.0313			1.1289			1.8566		35
Coal	Oil		Oil			Oil			36
Tons	Barrels		Barrels			Barrels			37
501587	1452	0	862	0	0	761	0	0	38
9184	140000	0	140000	0	0	140000	0	0	39
40.971	134.694	0.000	130.620	0.000	0.000	0.000	0.000	0.000	40
40.966	136.038	0.000	130.662	0.000	0.000	104.664	0.000	0.000	41
2.230	23.136	0.000	22.221	0.000	0.000	17.800	0.000	0.000	42
0.023	0.000	0.000	0.356	0.000	0.000	0.847	0.000	0.000	43
11399.000	0.000	0.000	18508.000	0.000	0.000	47830.000	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)
12/31/2013

Year/Period of Report
End of 2013/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) 12/31/2013	Year/Period of Report 2013/Q4
FOOTNOTE DATA			

Schedule Page: 402 Line No.: -1 Column: b

Coyote - Joint facility operated by Otter Tail Power Company

Schedule Page: 402 Line No.: -1 Column: c

Big Stone - Joint facility operated by Otter Tail Power Company

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Not applicable (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

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(Mo, Da, Yr)
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Year/Period of Report
End of 2013/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent
Otter Tail Power Company

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Date of Report
(Mo, Da, Yr)
12/31/2013

Year/Period of Report
End of 2013/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	0	FERC Licensed Project No. Plant Name: (d)	0	FERC Licensed Project No. Plant Name: (e)	0	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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						38

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	3,570	661,464
3	Wright	1922	0.40			949,707
4	Pisgah	1917	0.52	0.8	4,181	677,190
5	Dayton Hollow	1909	0.97	1.0	7,184	1,855,417
6	Taplin Gorge	1925	0.56	0.5	3,705	966,267
7	Bemidji	1941	0.74		-20	1,350,780
8						
9	Internal Combustion:					
10	Fergus Falls Control Center	1995	1.83	1.8	20	591,638
11	Diesel Generators		2.26	1.6		
12						
13	Wind Turbine Plants					
14	Langdon	2007	40.50	40.3	136,020	79,471,546
15	Ashtabula	2008	48.00	48.2	147,319	116,763,072
16	Luverne	2009	49.50	49.9	169,217	72,853,390
17						
18						
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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
844,782	10,709		27,979 -			2
	13,277		70,678 -			3
902,920	23,907		39,416 -			4
1,787,492	24,751		36,423 -			5
1,830,050	22,893		33,030 -			6
	32,944		51,570 -			7
						8
						9
321,892	1,363		16,884	Oil		10
				Oil		11
						12
						13
1,972,733	804,914		86,736			14
2,421,667	1,030,796		2,042			15
1,460,661	812,859		11,274			16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
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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) 12/31/2013	Year/Period of Report 2013/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	Center	Maple River	345.00	345.00	Alum Tower	48.00		1
2	Monticello	Quarry Sub	345.00	345.00	Steel Pole	29.00		1
3								
4	Fergus Falls	Inman	230.00	230.00	Wood H	19.00		1
5	Fergus Falls	Wahpeton	230.00	230.00	Wood H	29.00		1
6	Wahpeton	Hankinson	230.00	230.00	Wood H	26.00		1
7	Hankinson	Forman	230.00	230.00	Wood H	37.00		1
8	Forman	Ellendale	230.00	230.00	Wood H	47.00		1
9	Audubon (W 1/10)	Badoura	230.00	230.00	Wood H	6.00		1
10	Audubon	Sheyenne	230.00	230.00	Wood H	42.00		1
11	Winger (E 1/3)	Wilton	230.00	230.00	Alum H	18.00		1
12	Grand Forks (M 1/3)	Winnipeg	230.00	230.00	Wood H	27.00		1
13	Big Stone (N 1/3)	Hankinson	230.00	230.00	Wood H	23.00		1
14	Big Stone (S 1/4)	Blair	230.00	230.00	Wood H	15.00		1
15	Harvey	Coal Creek	230.00	230.00	Wood H	75.00		1
16	Balta	Harvey	230.00	230.00	Wood H	22.00		1
17	Rugby	Balta	230.00	230.00	Steel H	18.00		1
18	Wilton	Cass Lake	230.00	230.00	Steel H	19.00		1
19	Cass Lake	Boswell	230.00	230.00	Steel H	51.00		1
20								
21		Total	115.00	115.00	Wood H	468.00		
22		Total	115.00	115.00	SWP	410.00		
23		Total	69.00	69.00		208.00		
24								
25								
26		Total	41.60	41.60	SWP	3,757.00		
27		Total	41.60	41.60	Underground	1.00		
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	5,395.00		18

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)	
		5,458,744	5,458,744					1
	1,847,062	8,380,002	10,227,064					2
								3
	6,339	543,263	549,602					4
	5,935	669,322	675,257					5
		475,142	475,142					6
		765,639	765,639					7
		4,127,317	4,127,317					8
		185,155	185,155					9
		818,044	818,044					10
		1,852,883	1,852,883					11
		899,455	899,455					12
		722,275	722,275					13
		638,810	638,810					14
		10,586,713	10,586,713					15
		4,230,293	4,230,293					16
		3,389,667	3,389,667					17
	489,732	4,252,902	4,742,634					18
	567,058	10,799,868	11,366,926					19
								20
	74,783	7,263,169	7,337,952					21
	49,282	28,794,762	28,844,044					22
		6,352,015	6,352,015					23
								24
								25
	4,953	87,789,198	87,794,151					26
		72,673	72,673					27
								28
								29
								30
								31
								32
								33
				5,088,409	1,841,153	57,166	6,986,728	34
								35
	3,045,144	189,067,311	192,112,455	5,088,409	1,841,153	57,166	6,986,728	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) 12/31/2013	Year/Period of Report 2013/Q4
FOOTNOTE DATA			

Schedule Page: 422 Line No.: 34 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	Added:						
2	Buffalo	Casselton	16.00	Single Pole	19.00	2	
3							
4							
5							
6							
7							
8							
9							
10							
11							
12	Altered:						
13	Bemidji 115KV	Bemidji Nymore	-3.70	Single Pole	20.00	1	1
14	Parkers Prairie	Parkers Prairie	-0.30	Single Pole	22.00	1	
15	Herman	Wendell	1.80	Single Pole	20.00	1	1
16	Milbank South	Milbank NW	1.00	Single Pole	27.00	2	2
17	Spiritwood	Aviko/Cavendish	0.50	Single Pole	26.00	1	1
18	Edgeley	Jamestown	2.00	Single Pole	20.00		
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	TOTAL		17.30		154.00	8	5

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
795	ACSS	3651 P	115	330,260	2,573,897	1,189,773	-2,802	4,091,128	2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
3QR	ACSR	3051	69				-17,007	-17,007	13
3/O	ACSR	3050	41			1,168	3,340	4,508	14
30	ACSR	3102	41	23,628	72,252	28,098	13,249	137,227	15
10	ACSR	3102	41	2,953	100,936	85,982	11,006	200,877	16
477R	ACSR	3651 P	115		34,701	38,089	4,313	77,103	17
10	ACSR	3102	41	6,264	72,329	99,883	14,772	193,248	18
									19
									20
									21
									22
									23
									24
									25
									26
									27
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									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
									44
				363,105	2,854,115	1,442,993	26,871	4,687,084	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, SD Plant - 63314	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	Oakes, ND - 230 kv - 63362 - Not in Service	Transmission	230.00	41.60	
29	Ortonville, MN - 115 kv - 63216	Transmission	115.00	41.60	
30	Pelican Rapids, MN - 115 k - 63234	Transmission	115.00	41.60	
31	Plummer, MN - 115kv - 7967	Transmission	115.00	41.60	
32	Rugby, ND - 230 kv - 63373	Transmission	230.00	115.00	13.80
33	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	Wilton, MN 230 kV - 63345	Transmission	230.00	115.00	13.80
37	Winger, MN - 63238	Transmission	230.00	115.00	13.20
38					
39	Transmission Subtotal:		5980.00	2418.40	391.60
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	Transmission Total		6323.00	2631.00	404.10
8					
9	Bemidji, MN 25th Street	Distribution	69.00	12.50	
10	Bemidji, MN Airport	Distribution	41.60	12.50	
11	Bemidji, MN Nymore	Distribution	69.00	12.50	
12	Bemidji, MN Industrial Park	Distribution	69.00	12.50	
13	Bottineau, ND Downtown - Not in Service	Distribution	41.60	12.50	
14	Casselton, ND	Distribution	41.60	12.50	
15	Casselton, ND Ethanol Plant	Distribution	115.00	12.50	
16	Clearbrook, MN Pipeline	Distribution	115.00	4.16	
17	Cooperstown, ND	Distribution	41.60	12.50	
18	Crookston, MN Parkview	Distribution	41.60	12.50	
19	Crookston, MN South Main	Distribution	41.60	12.50	
20	Dawson, MN Dawson Mills	Distribution	115.00	12.50	
21	Devils Lake, ND Downtown	Distribution	41.60	4.16	
22	Enderlin, ND	Distribution	115.00	12.50	
23	Fairmount, ND	Distribution	115.00	12.50	
24	Fergus Falls, MN Edgetown	Distribution	115.00	12.50	
25	Fergus Falls, MN Hoot Lake	Distribution	115.00	12.50	
26	Fergus Falls, MN Southeast	Distribution	115.00	12.50	
27	Gwinner, ND	Distribution	115.00	12.50	
28	Harvey, ND Northwest	Distribution	115.00	12.50	
29	Itasca, MN Minnesota Pipeline	Distribution	115.00	4.16	
30	Jamestown, ND Downtown	Distribution	115.00	12.50	
31	Jamestown, ND North	Distribution	115.00	12.50	
32	Jamestown, ND Potato	Distribution	115.00	12.50	
33	Jamestown, ND Southwest	Distribution	41.60	12.50	
34	Lake Norden, SD Dairy	Distribution	41.60	12.50	
35	Lisbon, ND Town	Distribution	115.00	12.50	
36	Mahnomen, MN	Distribution	115.00	12.50	
37	Milbank, SD Northwest	Distribution	41.60	12.50	
38	Milbank, SD South	Distribution	41.60	12.50	
39	Morris, MN Northeast	Distribution	41.60	12.50	
40	Morris, MN South	Distribution	115.00	12.50	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
 2. Substations which serve only one industrial or street railway customer should not be listed below.
 3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
 4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Oakes, ND North	Distribution	41.60	12.50	
2	Parkers Prairie, MN	Distribution	41.60	12.50	
3	Pelican Rapids, MN Turkey Plant	Distribution	41.60	12.50	
4	Perham, MN	Distribution	115.00	12.50	
5	Rosholt, SD	Distribution	41.60	12.50	
6	Rugby, ND South	Distribution	41.60	12.50	
7	Spiritwood, ND	Distribution	115.00	12.50	
8	Wahpeton Inventory	Distribution	115.00	12.50	
9	Wahpeton Inventory	Distribution	41.60	12.50	
10	Wahpeton Inventory	Distribution	41.60	4.16	
11	Wahpeton, ND North 115 kv - 63230	Distribution	115.00	12.50	
12	Wahpeton, ND Northwest	Distribution	41.60	12.50	
13	Wheaton, MN South	Distribution	115.00	12.50	
14	Distribution Subtotal:		3569.00	529.14	
15	Distribution Under 10,000 kva	Distribution			
16	Distribution Total		3569.00	529.14	
17	Transmission From Above		6323.00	2631.00	404.10
18	Transmission & Distribution		9892.00	3160.14	404.10
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
						1
19	1					2
233	1					3
45	1					4
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
34	1					27
		1				28
22	1					29
13	1					30
34	1					31
125	1					32
17	1					33
45	1					34
		1				35
140	1					36
140	1					37
						38
2813	38	2				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
7	1					5
		1				6
2842	42	3				7
						8
20	1					9
14	1					10
14	1					11
11	1					12
	3					13
10	1					14
94	2					15
22	2					16
10	1					17
10	1					18
39	2					19
10	1					20
10	1					21
14	1					22
10	3					23
37	1					24
37	1					25
37	1					26
20	2					27
14	1					28
11	1					29
14	1					30
14	1					31
14	1					32
14	1					33
12	1					34
14	1					35
14	1					36
25	1					37
10	1					38
12	1					39
12	3					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)	
10	3					1
10	1					2
10	1					3
28	2					4
10	1					5
10	1					6
84	2					7
		2				8
		3				9
		1				10
24	2					11
20	2					12
12	1					13
817	58	6				14
974	1113					15
1791	1171	6				16
2844	42	3				17
4645	1213	9				18
						19
						20
						21
						22
						23
						24
						25
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						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) 12/31/2013	Year/Period of Report 2013/Q4
FOOTNOTE DATA			

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

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

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

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2	Construction work in progress	Otter Tail Corporation	107	51,486
3	Insurance	Otter Tail Corporation	165	73,334
4	Miscellaneous deferred debits	Otter Tail Corporation	186	6,456
5	Civic and political activities	Otter Tail Corporation	426.4	6,175
6	Dividends - common stock	Otter Tail Corporation	438	34,505,367
7	Corporate allocated A&G expense	Otter Tail Corporation	See Note	7,962,295
8				
9	Construction work in progress	Aevenia Inc	107	505,242
10	Other electric revenues	Aevenia Inc	456	98,988
11				
12				
13				
14				
15				
16				
17				
18				
19	Other electric revenues			
20	Non-power Goods or Services Provided for Affiliate			
21	Printing, design & mailing services	Otter Tail Corporation	417	167,736
22	Other deductions	Otter Tail Corporation	426.5	283,913
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) 12/31/2013	Year/Period of Report 2013/Q4
Otter Tail Power Company			
FOOTNOTE DATA			

Schedule Page: 429 Line No.: 7 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.: 7 Column: c

The following accounts were charged:

500	23,655
506	5,785
539	23
920	3,761,211
921	2,487,461
923	360,483
924	1,392
925	158,495
926	15,326
928	8,649
930.1	17,467
930.2	851,758
931	82,734
935	187,856

Total	7,962,295

INDEX

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

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

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

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

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