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

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 1/31/2012)

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

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Otter Tail Power Company	**End of** 2009/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.)

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent Otter Tail Power Company	02 Year/Period of Report End of 2009/Q4
03 Previous Name and Date of Change *(if name changed during year)* Otter Tail Corporation 07/01/2009	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 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 *(Street, City, State, Zip Code)* PO Box 496, Fergus Falls, MN 56538-0496	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(218) 739-8291	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009

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 / 02 Title	03 Signature	04 Date Signed *(Mo, Da, Yr)*
01 Name Kevin Moug 02 Title CFO, Otter Tail Corporation	Kevin Moug	04/12/2010

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	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	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	Not applicable
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Sales of Electricity by Rate Schedules	304	
44	Sales for Resale	310-311	
45	Electric Operation and Maintenance Expenses	320-323	
46	Purchased Power	326-327	
47	Transmission of Electricity for Others	328-330	
48	Transmission of Electricity by ISO/RTOs	331	Not applicable
49	Transmission of Electricity by Others	332	
50	Miscellaneous General Expenses-Electric	335	
51	Depreciation and Amortization of Electric Plant	336-337	
52	Regulatory Commission Expenses	350-351	
53	Research, Development and Demonstration Activities	352-353	
54	Distribution of Salaries and Wages	354-355	
55	Common Utility Plant and Expenses	356	Not applicable
56	Amounts included in ISO/RTO Settlement Statements	397	
57	Purchase and Sale of Ancillary Services	398	
58	Monthly Transmission System Peak Load	400	
59	Monthly ISO/RTO Transmission System Peak Load	400a	Not applicable
60	Electric Energy Account	401	
61	Monthly Peaks and Output	401	
62	Steam Electric Generating Plant Statistics	402-403	
63	Hydroelectric Generating Plant Statistics	406-407	Not applicable
64	Pumped Storage Generating Plant Statistics	408-409	Not applicable
65	Generating Plant Statistics Pages	410-411	
66	Transmission Line Statistics Pages	422-423	

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 Lines Added During the Year	424-425	
68	Substations	426-427	
69	Transactions with Associated (Affiliated) Companies	429	
70	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [ ] Two copies will be submitted [ ] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

GENERAL INFORMATION

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

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) [X] No

CONTROL OVER RESPONDENT

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

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)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President and Chief Executive Officer, Utility	Charles S. MacFarlane	441,983
2			
3	Senior Vice President, Supply	Ward L. Uggerud	329,935
4			
5	Vice President, Asset Management	Rodney C.H. Scheel	203,899
6			
7	Vice President, Customer Service	Mark H. Helland	188,734
8			
9	Vice President, Administration	Thomas R. Brause	221,079
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11	Vice President, Finance	George D. Bell	207,121
12			
13	Vice President, Renewable Energy Development	Todd R. Wahlund	373,633
14	& Risk Management		
15			
16	Chief Financial Officer * **	Kevin G. Moug	496,699
17			
18	Secretary * **	George A. Koeck	410,482
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20	Treasurer * **	Suzanne Allen	163,200
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23	* This individual is an employee of		
24	Otter Tail Corporation.		
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26	** Only a portion of this individual's salary is		
27	allocated to respondent.		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1		
2	John D. Erickson	Fergus Falls, Minnesota
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4	Lauris N. Molbert	Fargo, North Dakota
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

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

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

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	MISO's FERC Electric Tariff, 4th Revised Vol. 1	Attachment O, ER98-1438
2	MISO's FERC Electric Tariff, 4th Revised Vol. 1	Attachment GG, ER06-18
3		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/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
[X] 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
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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	NA	NA	NA
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

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 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

1. None.
2. None.
3. None.
4. None.
5. None.
6. On May 22, 2009, Otter Tail Corporation, dba Otter Tail Power Company (now known as Otter Tail Power Company) entered into a Term Loan Agreement (the Loan Agreement) with JPMorgan Chase Bank, N.A., as administrative agent, KeyBank National Association, as syndication agent, Union Bank, N.A., as documentation agent, and the banks named therein. The Loan Agreement provides for a $75 million term loan to Otter Tail Power Company (the Company) due May 20, 2011, which was fully drawn on May 22, 2009. Borrowings under the Loan Agreement bear interest at a rate equal to the base rate in effect from time to time. The base rate is a fluctuating rate per annum equal to (i) the highest of (A) JPMorgan Chase Bank, N.A.'s prime rate, (B) the Federal funds effective rate plus 0.5% per annum, and (C) a daily LIBOR rate plus 1.0% per annum, plus (ii) a margin of 1.5% to 3.0% determined on the basis of the Company's senior unsecured credit ratings, as provided in the Loan Agreement. At the Company's option, the interest rate on outstanding borrowings may be converted to a LIBOR rate that would fluctuate based on the rate at which deposits of U.S. dollars in the London interbank market are quoted, plus a margin of 2.5% to 4.0% determined on the basis of the Company's senior unsecured credit ratings, as provided in the Loan Agreement. The Company used the proceeds borrowed under the Loan Agreement to support its working capital needs and other capital requirements, including construction of the Luverne Wind Farm in North Dakota. The interest rate on borrowings under the Loan Agreement was 3.73% at December 31, 2009. The Loan Agreement contains a number of restrictions on the business of the Company, including restrictions on its ability to merge, sell assets, make certain investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Loan Agreement also contains certain financial covenants. Specifically, the Company must not permit the ratio of its "Interest-bearing Debt" to "Total Capitalization" (each as defined in the Loan Agreement) to be greater than 0.60 to 1.00, or permit its "Interest and Dividend Coverage Ratio" (as defined in the Loan Agreement) for any period of four consecutive fiscal quarters to be less than 1.50 to 1.00. The Loan Agreement also contains affirmative covenants and events of default. The Loan Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the Company's credit ratings. The obligations of the Company under the Term Loan Agreement are unsecured. Since completion of the Company's holding company formation on July 1, 2009, the Loan Agreement is an obligation of the Company (see item 7 on this page). In November 2009, the Company paid down $17 million of the $75 million term loan. The Company paid off the remaining $58 million balance in January 2010, using lower cost funds available under the Company's credit agreement described below. The Company did not incur any penalties for the early repayments and retirement of its debt under the Loan Agreement.

   The Company has in place a credit agreement providing for a $170 million line of credit with an accordion feature whereby the line can be increased to $250 million as described in the credit agreement. The credit agreement is between Otter Tail Corporation, dba Otter Tail Power Company (now known as Otter Tail Power Company) and JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association and Merrill Lynch Bank USA, as Banks, U.S. Bank National Association, as a Bank and as agent for the Banks, and Bank of America, N.A., as a Bank and as Syndication Agent. This line is an unsecured revolving credit facility the Company can draw on to support the working capital needs and other capital requirements of the Company's electric operations. Borrowings under this line of credit bear interest at LIBOR plus 0.5%, subject to adjustment based on the ratings of the Company's senior unsecured debt. The agreement contains a number of restrictions on the business, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The agreement also contains affirmative covenants and events of default. This credit agreement is subject to renewal on July 30, 2011. As of December 31, 2009, $1,585,324 was borrowed under this credit agreement.

   Minnesota Public Utilities Commission authorization given under Docket No. E-017/S-08-362 dated June 24, 2008.

7. Effective July 1, 2009, Otter Tail Corporation completed a restructuring where the electric utility operations of Otter Tail Corporation became a subsidiary of a new holding company with substantially similar articles and bylaws. Otter Tail Corporation obtained authority for this reorganization in the Federal Energy Regulatory Commission's "Order Authorizing Disposition of Jurisdictional Facilities" issued August 18, 2008, in Docket No. EC08-97-000. Approval was also obtained from the Minnesota Public Utilities Commission in Docket No. E-017/PA-08-658 dated January 7, 2009, from the North Dakota Public Service Commission in Case No. PU-08-292 dated October 8, 2008, and from the South Dakota Public Utilities Commission in Order No. EL08-025 dated November 13, 2008.
8. Wages for Local Union 1570 were increased by 4.0% effective September 1, 2009. Wages for Local Union 203, 239, 524 and 949 were increased by 2% effective November 1, 2009.
9. Sierra Club Complaint: On June 10, 2008 the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) against the Company and two other co-owners of Big Stone Generating Station (Big Stone). The

complaint alleged certain violations of the Prevention of Significant Deterioration and New Source Performance Standards (NSPS) provisions of the Clean Air Act and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleged the defendants modified and operated Big Stone without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the Clean Air Act and the South Dakota SIP. The Sierra Club alleged the defendants' actions have contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club sought both declaratory and injunctive relief to bring the defendants into compliance with the Clean Air Act and the South Dakota SIP and to require the defendants to remedy the alleged violations. The Sierra Club also seeks unspecified civil penalties, including a beneficial mitigation project. The Company believes these claims are without merit and that Big Stone was and is being operated in compliance with the Clean Air Act and the South Dakota SIP.

The defendants filed a motion to dismiss the Sierra Club complaint on August 12, 2008. On March 31, 2009 and April 6, 2009, the District Court issued a Memorandum and Order and Amended Memorandum and Order, respectively, granting the defendants' motion to dismiss the Sierra Club complaint. On April 17, 2009 the Sierra Club filed a motion for reconsideration of the Amended Memorandum Opinion and Order. The Sierra Club motion was opposed by the defendants. The Sierra Club motion for reconsideration was denied on July 22, 2009. On July 30, 2009 the Sierra Club filed a notice of appeal to the 8th U.S. Circuit Court of Appeals. The briefing schedule calls for the appellant to submit its brief by mid-October, for appellees to submit their brief by mid-November and for the appellant to submit its reply brief by the end of November. On October 13, 2009, the United States Department of Justice filed a motion seeking a 30-day extension of the time to file an amicus brief in support of the Sierra Club's position. The Court of Appeals granted this motion, as well as the appellees' subsequent joint motion with the Sierra Club, extending the time to file the appellees' brief and the Sierra Club's reply brief. Briefing was complete on January 22, 2010 on filing of the Sierra Club's reply brief. The ultimate outcome of this matter cannot be determined at this time.

Federal Power Act Complaint

On August 29, 2008 Renewable Energy System Americas, Inc. (RES), a developer of wind generation, and PEAK Wind Development, LLC (PEAK Wind), a group of landowners in Barnes County, North Dakota, filed a complaint with the FERC alleging that the Company and Minnkota Power Cooperative, Inc. (Minnkota) had acted together in violation of the Federal Power Act (FPA) to deny RES and PEAK Wind access to the Pillsbury Line, an interconnection facility which Minnkota owns to interconnect generation projects being developed by the Company and NextEra Energy Resources, Inc. (fka FPL Energy, Inc.) (NextEra). RES and PEAK Wind asked that (1) the FERC order Minnkota to interconnect its Glacier Ridge project to the Pillsbury Line, or in the alternative, (2) the FERC direct MISO to interconnect the Glacier Ridge project to the Pillsbury Line. RES and Peak Wind also requested that the Company, Minnkota and NextEra pay any costs associated with interconnecting the Glacier Ridge Project to the MISO transmission system which would result from the interconnection of the Pillsbury Line to the Minnkota transmission system, and that the FERC assess civil penalties against the Company. The Company answered the complaint on September 29, 2008, denying the allegations of RES and PEAK Wind and requesting that the FERC dismiss the complaint. On October 14, 2008, RES and PEAK Wind filed an answer to the Company's answer and, restated the allegations included in the initial complaint. RES and PEAK Wind also added a request that the FERC rescind both the Company's waiver from the FERC Standards of Conduct and its market-based rate authority. On October 28, 2008, the Company filed a reply, denying the allegations made by RES and PEAK Wind in its answer. By order issued on December 19, 2008, the FERC set the complaint for hearing and established settlement procedures. A formal settlement agreement was filed with the FERC requesting approval of the settlement and withdrawal of the complaint. The Company expects the FERC will issue an order approving the settlement and terminating the proceeding. The settlement is not expected to have a material impact on the Company's financial position or results of operations.

10. As described in item 7 above, following the holding company formation Otter Tail Power Company became a subsidiary of Otter Tail Corporation. Cascade Investment L.L.C. owns approximately 9.6% of Otter Tail Corporation's outstanding common shares as of December 31, 2009, and is the holder of $50 million aggregate principal amount of Otter Tail Corporation's 8.89% senior notes due November 30, 2017.

11. (Reserved.)

12. None.

13. As described in item 7 above, on July 1, 2009 Otter Tail Corporation completed a holding company reorganization whereby Otter Tail Power Company, 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. As a result Otter Tail Corporation is the sole shareholder of Otter Tail Power Company. Directors for Otter Tail Power Company are John Erickson, President & CEO, Otter Tail Corporation, and Lauris Molbert, Executive Vice President & COO, Otter Tail Corporation.

14. Not applicable.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	1,313,015,061	1,205,646,725
3	Construction Work in Progress (107)	200-201	11,103,572	25,546,667
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,324,118,633	1,231,193,392
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	492,901,483	467,854,874
6	Net Utility Plant (Enter Total of line 4 less 5)		831,217,150	763,338,518
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)		831,217,150	763,338,518
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		776,046	3,869,529
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	2,124,410
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	382,335,879
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)		515,317	2,485,691
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		877,461	18,282,987
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)		2,168,824	404,849,676
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		9,403	6,431,324
36	Special Deposits (132-134)		212,388	1,321,533
37	Working Fund (135)		20,605	22,530
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		50,000	50,000
40	Customer Accounts Receivable (142)		17,003,406	16,950,364
41	Other Accounts Receivable (143)		4,543,932	30,664,358
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		983,563	734,628
43	Notes Receivable from Associated Companies (145)		37,346	35,450,210
44	Accounts Receivable from Assoc. Companies (146)		90,747	411,562
45	Fuel Stock (151)	227	8,314,739	7,613,394
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	15,773,009	15,401,553
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	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)		325,011	1,203,603
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)		15,839,547	24,030,090
62	Miscellaneous Current and Accrued Assets (174)		40,629,524	353,863
63	Derivative Instrument Assets (175)		8,320,668	404,961
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		110,186,762	139,574,717
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		4,823,171	3,044,662
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	12,981,726	0
72	Other Regulatory Assets (182.3)	232	103,657,765	82,043,464
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)		130,381	-2,237
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	1,926,695	342,508
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)		3,051,183	3,357,462
82	Accumulated Deferred Income Taxes (190)	234	112,915,335	83,821,092
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		239,486,256	172,606,951
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,183,058,992	1,480,369,862

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

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

On July 1, 2009 Otter Tail Power Company, 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 (formerly known as Otter Tail Holding Company). This footnote shows how pages 110-113 would have been prepared if Otter Tail Power Company had been a wholly owned subsidiary in 2008.

Otter Tail Power Company — **End of 2009/Q4**

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account	Current year End of Quarter/Year Balance	Prior Year End Balance 12/31
1	**UTILITY PLANT**		
2	Utility plant (101-106, 114)	$ 1,313,015,061	$ 1,205,646,725
3	Construction work in progress (107)	11,103,572	25,546,667
4	Total utility plant (Enter Total of lines 2 and 3)	1,324,118,633	1,231,193,392
5	Less: Accumulated provision for depr. and amort. (108, 110, 111, 115)	492,901,483	467,854,874
6	Net Utility Plant (Enter Total of line 4 less 5)	831,217,150	763,338,518
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	-	-
8	Nuclear Fuel Material and Assemblies-Stock Acct (120.2)	-	-
9	Nuclear Fuel Assemblies in Reactor (120.3)	-	-
10	Spent Nuclear Fuel (120.4)	-	-
11	Nuclear Fuel Under Capital Leases (120.6)	-	-
12	(Less) Accum. Prov. For Amort. Of Nucl. Fuel Assemblies (120.5)	-	-
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)	-	-
14	Net Utility Plant (Enter Total of lines 6 and 13)	831,217,150	763,338,518
15	Utility Plant Adjustments (116)	-	-
16	Gas stored underground - Noncurrent (117)	-	-
17	**OTHER PROPERTY AND INVESTMENTS**		
18	Non-utility property (121)	776,046	902,006
19	Less: accum. prov. for depr. and amort.(122)	-	-
20	Investments in Associated Companies (123)	-	-
21	Investment in subsidiary companies (123.1)	-	-
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)		
23	Noncurrent Portion of Allowances	-	-
24	Other investments (124)	515,317	1,059,258
25	Sinking Funds (125)	-	-
26	Depreciation Fund (126)	-	-
27	Amortization Fund - Federal (127)	-	-
28	Other special funds (128)	877,461	-
29	Special Funds (Non major Only) (129)	-	-
30	Long-Term Portion of Derivative Assets (175)	-	-
31	Long-Term Portion of Derivative Assets - Hedges (176)	-	-
32	Total other property and investments (lines 18-21 and 23-31)	2,168,824	1,961,264
33	**CURRENT AND ACCRUED ASSETS**		
34	Cash and Working funds (Non major only) (130)	-	-
35	Cash (131)	9,403	7,902
36	Special deposits (132-134)	212,388	813,242
37	Working funds (135)	20,605	22,530
38	Temporary cash investments (136)	-	-
39	Notes receivable (141)	50,000	50,000
40	Customer accounts receivable (142)	17,003,406	16,950,364
41	Other accounts receivable (143)	4,543,932	30,614,069
42	(Less) Accum. prov. for uncollectible acct. - credit (144)	983,563	734,628
43	Notes receivable from associated companies (145)	37,346	32,345
44	Accounts receivable from assoc. companies (146)	90,747	209,454
45	Fuel stock (151)	8,314,739	7,613,394
46	Fuel Stock Expenses Undistributed (152)	-	-
47	Residuals (Elec) and Extracted Products (153)	-	-
48	Plant materials and operating supplies (154)	15,773,009	15,401,553

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

49	Merchandise (155)	-	-
50	Other material and supplies (156)	-	-
51	Nuclear Materials Held for Sale (157)	-	-
52	Allowances (158.1 and 158.2)	-	-

Page 110 - Footnotes

Schedule Page: 110 Line No.: 53 Column: c

Otter Tail Power Company **End of 2009/Q4**

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

Line No.	Title of Account	Current year End of Quarter/Year Balance	Prior Year End Balance 12/31
53	(Less) Noncurrent Portion of Allowances	-	-
54	Stores Expense Undistributed (163)	-	-
55	Gas stored underground - Current (164.1)	-	-
56	Liquefied Natural Gas Stored and Held for processing (164.2-164.3)	-	-
57	Prepayments (165)	325,011	195,243
58	Advances for Gas (166-167)	-	-
59	Interest and Dividends Receivable (171)	-	-
60	Rents Receivable (172)	-	-
61	Accrued utility revenues (173)	15,839,547	24,030,090
62	Miscellaneous current and accrued assets (174)	40,629,524	353,863
63	Derivative instrument assets (175)	8,320,668	404,961
64	(Less) Long Term Portion of Derivative Instrument Assets (175)	-	-
65	Derivative Instrument Assets - Hedges (176)	-	-
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)	-	-
67	Total current and accrued assets (lines 34 through 66)	110,186,762	95,964,382
68	**DEFERRED DEBITS**		
69	Unamortized debt expense (181)	4,823,171	1,560,519
70	Extraordinary Property Losses (182.1)	-	-
71	Unrecovered Plant and Regulatory Study Costs (182.2)	12,981,726	-
72	Other regulatory assets (182.3)	103,657,765	82,043,464
73	Prelim. survey and investigation charges (electric) (183)	-	-
74	Preliminary Natural Gas Survey and Investigation Charges (183.1)	-	-
75	Other preliminary Survey and Investigation Charges (183.2)	-	-
76	Clearing accounts (184)	130,381	(2,237)
77	Temporary Facilities (185)	-	-
78	Miscellaneous deferred debits (186)	1,926,695	342,508
79	Def. Losses from Disposition of Utility Plt. (187)	-	-
80	Research, Devel., and Demonstration Expend. (188)	-	-
81	Unamortized loss on reacquired debt (189)	3,051,183	3,357,462
82	Accumulated deferred income taxes (190)	112,915,335	77,922,806
83	Unrecovered Purchased Gas Costs (191)	-	-
84	Total deferred debits (lines 69 through 83)	239,486,256	165,224,522
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)	$ 1,183,058,992	$ 1,026,488,686

Page 111- Footnote

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	end of 2009/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	500	176,923,100
3	Preferred Stock Issued (204)	250-251	0	15,500,000
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	241,088,430
7	Other Paid-In Capital (208-211)	253	204,860,891	10,482,866
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	9,840,795
11	Retained Earnings (215, 215.1, 216)	118-119	125,828,740	98,652,349
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	161,711,312
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)	-653,159	-2,999,682
16	Total Proprietary Capital (lines 2 through 15)		330,036,972	691,517,580
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	280,925,000	331,190,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	15,500,000	0
21	Other Long-Term Debt (224)	256-257	58,000,000	4,657,140
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)		354,425,000	335,847,140
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)		956,000	956,000
29	Accumulated Provision for Pensions and Benefits (228.3)		123,170,288	129,390,297
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	1,381,594
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)		4,049,995	3,297,729
35	Total Other Noncurrent Liabilities (lines 26 through 34)		128,176,283	135,025,620
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		1,585,324	27,064,471
38	Accounts Payable (232)		33,889,178	41,895,134
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		1,055,186	3,444,094
41	Customer Deposits (235)		791,669	700,250
42	Taxes Accrued (236)	262-263	10,142,995	9,331,745
43	Interest Accrued (237)		4,595,614	4,915,854
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Otter Tail Power Company	(1) [x] An Original (2) [ ] A Resubmission	12/31/2009	end of 2009/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		967,077	1,034,288
48	Miscellaneous Current and Accrued Liabilities (242)		997,921	4,073,091
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		14,680,553	1,690,283
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)		68,705,517	94,149,210
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	47,660,172	34,287,700
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	421,881	348,770
60	Other Regulatory Liabilities (254)	278	17,379,877	18,006,714
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)		225,341,183	167,388,250
64	Accum. Deferred Income Taxes-Other (283)		10,912,107	3,798,878
65	Total Deferred Credits (lines 56 through 64)		301,715,220	223,830,312
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,183,058,992	1,480,369,862

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 12/31/2009	2009/Q4

FOOTNOTE DATA

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

Otter Tail Power Company **End of 2009/Q4**

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account	Current year End of Quarter/Year Balance	Prior Year End Balance 12/31
1	**PROPRIETARY CAPITAL**		
2	Common stock issued (201)	$ 500	$ -
3	Preferred stock issued (204)	-	15,500,000
4	Capital Stock subscribed (202, 205)	-	-
5	Stock Liability for Conversion (203, 206)	-	-
6	Premium on common stock (207)	-	-
7	Other paid-in capital (208-211)	204,860,891	195,192,363
8	Installments Received on Capital Stock (212)	-	-
9	(Less) Discount on Capital Stock (213)	-	-
10	(Less) Capital stock expense (214)	-	-
11	Retained earnings - Parent (215, 215.1, 216)	125,828,740	125,963,422
12	Unappropriated undistributed subsidiary earnings (216.1)	-	-
13	(Less) Reacquired Capital Stock (217)	-	-
14	Noncorporate Proprietorship (non major only) (218)	-	-
15	Accumulated other comprehensive income (219)	(653,159)	(3,674,541)
16	Total proprietary capital (lines 2 through 15)	330,036,972	332,981,244
17	**LONG-TERM DEBT**		
18	Bonds (221)	280,925,000	256,790,000
19	(Less) Reaquired Bonds (222)	-	-
20	Advances from Associated Companies (223)	15,500,000	-
21	Other long-term debt (224)	58,000,000	-
22	Unamortized Premium on Long Term Debt (225)	-	-
23	(Less) Unamortized discount on long-term debt - debit (226)	-	-
24	Total long-term debt (lines 18-23)	354,425,000	256,790,000
25	**OTHER NONCURRENT LIABILITIES**		
26	Obligations under capital leases - noncurrent (227)	-	-
27	Accumulated provision for property insurance (228.1)	-	-
28	Accumulated provision for injuries and damages (228.2)	956,000	956,000
29	Accumulated provision for pensions and benefits (228.3)	123,170,288	118,421,588
30	Accumulated miscellaneous operating provisions (228.4)	-	-
31	Accumulated provision for rate refunds (229)	-	-
32	Long-Term Portion of Derivative Instrument Liabilities	-	-
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges	-	-
34	Asset retirement oblibations (230)	4,049,995	3,297,729
35	Total other noncurrent liabilities (lines 26 through 34)	128,176,283	122,675,317
36	**CURRENT AND ACCRUED LIABILITIES**		
37	Notes payable (231)	1,585,324	27,064,471
38	Accounts payable (232)	33,889,178	38,577,637
39	Notes payable to associated companies (233)	-	-
40	Accounts payable to associated companies (234)	1,055,186	1,077,926
41	Customer deposits (235)	791,669	700,250
42	Taxes accrued (236)	10,142,995	12,764,612
43	Interest accrued (237)	4,595,614	3,956,937
44	Dividends declared (238)	-	-
45	Matured long-term debt (239)	-	-

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Schedule Page: 112 Line No.: 46 Column: c

Otter Tail Power Company **End of 2009/Q4**

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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

Line No.	Title of Account	Current year End of Quarter/Year Balance	Prior Year End Balance 12/31
46	Matured interest (240)	-	-
47	Tax collections payable (241)	967,077	1,034,275
48	Miscellaneous current and accrued liabilities (242)	997,921	4,339,455
49	Obligations under capital leases - current (243)	-	-
50	Derivative instrument liabilities (244)	14,680,553	1,690,283
51	(Less) Long-Term Portion of Derivative Instrument Liabilities	-	-
52	Derivative Instrument Liabilities - Hedges (245)	-	-
53	(Less) Long-Term Portion of Derivative Instrument Liabilities - Hedges	-	-
54	Total current and accrued liabilities (lines 37 through 53)	68,705,517	91,205,846
55	**DEFERRED CREDITS**		
56	Customer Advances for Construction (252)	-	-
57	Accumulated deferred investment tax credits (255)	47,660,172	34,287,700
58	Deferred Gains from Disposition of Utility Plant (256)	-	-
59	Other deferred credits (253)	421,881	348,770
60	Other Regulatory liabilities (254)	17,379,877	18,006,714
61	Unamortized gain on reacquired debt (257)	-	-
62	Accum. Deferred Income Taxes - Accel. Amort. (281)	-	-
63	Accum. deferred income taxes - other property (282)	225,341,183	167,388,250
64	Accum. deferred income taxes - other (283)	10,912,107	2,804,845
65	Total deferred credits (lines 56 through 64)	301,715,220	222,836,279
66	**TOTAL LIABILITIES AND STOCKHOLDER EQUITY** (lines 16,24,35,54,and 65)	$ 1,183,058,992	$ 1,026,488,686

Page 113 - Footnote

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	307,777,047	324,979,144		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	190,101,018	207,800,583		
5	Maintenance Expenses (402)	320-323	25,945,289	27,944,302		
6	Depreciation Expense (403)	336-337	34,951,884	29,789,956		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	45,895	27,372		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	554,715	622,466		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	93,289	93,289		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		511,906	2,301,007		
13	(Less) Regulatory Credits (407.4)		1,078,123	3,917,514		
14	Taxes Other Than Income Taxes (408.1)	262-263	8,845,653	8,947,060		
15	Income Taxes - Federal (409.1)	262-263	-42,631,443	-23,679,888		
16	- Other (409.1)	262-263	1,490,950	-2,318,070		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	72,527,758	55,423,957		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	29,427,922	16,974,890		
19	Investment Tax Credit Adj. - Net (411.4)	266	-2,330,610	-1,691,710		
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)		15,537	106,952		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		301,652	126,674		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		259,886,374	284,387,642		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		47,890,673	40,591,502		

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
307,777,047	324,979,144					2
						3
190,101,018	207,800,583					4
25,945,289	27,944,302					5
34,951,884	29,789,956					6
45,895	27,372					7
554,715	622,466					8
93,289	93,289					9
						10
						11
511,906	2,301,007					12
1,078,123	3,917,514					13
8,845,653	8,947,060					14
-42,631,443	-23,679,888					15
1,490,950	-2,318,070					16
72,527,758	55,423,957					17
29,427,922	16,974,890					18
-2,330,610	-1,691,710					19
						20
						21
15,537	106,952					22
						23
301,652	126,674					24
259,886,374	284,387,642					25
47,890,673	40,591,502					26

Name of Respondent Otter Tail Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		47,890,673	40,591,502		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		1,339,983	10,845,228		
34	(Less) Expenses of Nonutility Operations (417.1)		806,539	8,928,007		
35	Nonoperating Rental Income (418)		42,966	43,545		
36	Equity in Earnings of Subsidiary Companies (418.1)	119		12,993,570		
37	Interest and Dividend Income (419)		102,462	2,615,073		
38	Allowance for Other Funds Used During Construction (419.1)		3,179,824	2,786,095		
39	Miscellaneous Nonoperating Income (421)		24,363,808	29,897,729		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		28,222,504	50,253,233		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			-16,095		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		369,917	527,795		
46	Life Insurance (426.2)			-140,752		
47	Penalties (426.3)		4,960	108		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		152,947	117,856		
49	Other Deductions (426.5)		21,068,799	38,074,113		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		21,596,623	38,563,025		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	7,231	1,861		
53	Income Taxes-Federal (409.2)	262-263	431,401	1,970,636		
54	Income Taxes-Other (409.2)	262-263	362,377	-6,219,847		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,277,591	2,202,238		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,053,808	2,144,401		
57	Investment Tax Credit Adj.-Net (411.5)		-673	-673		
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		1,024,119	-4,190,186		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		5,601,762	15,880,394		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		18,612,462	20,612,217		
63	Amort. of Debt Disc. and Expense (428)		1,107,267	327,444		
64	Amortization of Loss on Reaquired Debt (428.1)		306,279	387,973		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)			89		
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		423,796	1,712,137		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,036,181	1,692,397		
70	Net Interest Charges (Total of lines 62 thru 69)		19,413,623	21,347,285		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		34,078,812	35,124,611		
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)		34,078,812	35,124,611		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

Schedule Page: 114 Line No.: 2 Column: c

On July 1, 2009 Otter Tail Power Company, 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 (formerly known as Otter Tail Holding Company). This footnote shows how pages 114-117 would have been prepared if Otter Tail Power Company had been a wholly owned subsidiary in 2008.

Otter Tail Power Company — **End of 2009/Q4**

STATEMENT OF INCOME

Line No.	Title of Account	Total Current Year to Date Balance for Quarter/Year	Total Prior Year to Date Balance for Quarter/Year	Current 3 Months Ended Quarterly Only No 4th Quarter	Prior 3 Months Ended Quarterly Only No 4th Quarter
1	UTILITY OPERATING INCOME				
2	Operating revenues (400)	$ 307,777,047	$ 324,979,143		
3	Operating expenses				
4	Operation expenses (401)	190,101,018	207,800,583		
5	Maintenance expenses (402)	25,945,289	27,944,302		
6	Depreciation expense (403)	34,951,884	29,789,956		
7	Depreciation expense for asset retirement costs (403.1)	45,895	27,372		
8	Amort. and depl. of utility plant (404-405)	554,715	622,466		
9	Amort. of utility plant acq. adj. (406)	93,289	93,289		
10	Amort. Property Losses, Unrecov Plant & Regulatory Study Costs (407)	-	-		
11	Amort. Of Conversion Expenses (407)	-	-		
12	Regulatory Debits (407.3)	511,906	2,301,007		
13	(Less) Regulatory credits (407.4)	1,078,123	3,917,513		
14	Taxes other than income taxes (408.1)	8,845,653	8,947,060		
15	Income taxes - federal (409.1)	(42,631,443)	(23,679,888)		
16	Income taxes - other (409.1)	1,490,950	(2,318,070)		
17	Provision for deferred income taxes (410.1)	72,527,758	55,423,957		
18	(Less) Provision for deferred income taxes - credit (411.1)	29,427,922	16,974,890		
19	Investment tax credit adj. - net (411.4)	(2,330,610)	(1,691,710)		
20	(Less) Gains from Disp. Of Utility Plant (411.6)	-	-		
21	Losses from Disp. Of Utility Plant (411.8)	-	-		
22	(Less) Gains from disposition of allowances (411.8)	15,537	106,952		
23	Losses from Disposition of Allowances (411.9)	-	-		
24	Accretion expense (411.10)	301,652	126,674		
25	Total utility operating expenses	259,886,374	284,387,643	-	-
26	Net Util Oper Inc (Enter total line 2 less 25) Carry to page 117, line 27	47,890,673	40,591,500	-	-

Page 114 - Footnote

Schedule Page: 114 Line No.: 2 Column: g

Otter Tail Power Company — **End of 2009/Q4**

STATEMENT OF INCOME (Continued)

ELECTRIC UTILITY Current Year to date (in dollars)	ELECTRIC UTILITY Previous Year to date (in dollars)	GAS UTILITY Current Year to date (in dollars)	GAS UTILITY Previous Year to date (in dollars)	OTHER UTILITY Current Year to date (in dollars)	OTHER UTILITY Previous Year to date (in dollars)	Line No.
						1
$ 307,777,047	$ 324,979,143					2
						3
190,101,018	207,800,583					4
25,945,289	27,944,302					5
34,951,884	29,789,956					6
45,895	27,372					7
554,715	622,466					8
93,289	93,289					9

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

-	-					10
-	-					11
511,906	2,301,007					12
1,078,123	3,917,513					13
8,845,653	8,947,060					14
(42,631,443)	(23,679,888)					15
1,490,950	(2,318,070)					16
72,527,758	55,423,957					17
29,427,922	16,974,890					18
(2,330,610)	(1,691,710)					19
-	-					20
-	-					21
15,537	106,952					22
-	-					23
301,652	126,674					24
259,886,374	284,387,643					25
47,890,673	40,591,500					26

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Schedule Page: 114 Line No.: 27 Column: c

Otter Tail Power Company **End of 2009/Q4**

STATEMENT OF INCOME (Continued)

Line No.	Title of Account	Total Current Year to Date Balance for Quarter/Year	Total Prior Year to Date Balance for Quarter/Year	Current 3 Months Ended Quarterly Only No 4th Quarter	Prior 3 Months Ended Quarterly Only No 4th Quarter
27	Net utility operating income (Carried forward from page 114)	47,890,673	40,591,500	-	-
28	Other Income & Deductions				
29	Other Income				
30	Nonutility operating income				
31	Revenues from Merchandising, Jobbing, and Contract Work (415)	-	-		
32	(Less) Costs and exp. of merchandising, jobbing, and contract work (416)	-	-		
33	Revenues from nonutility operations (417)	1,339,983	10,845,227		
34	(Less) Expenses of nonutility operations (417.1)	806,539	8,928,007		
35	Nonoperating rental income (418)	42,966	43,545		
36	Equity in earnings of subsidiary companies (418.1)	-	-		
37	Interest and dividend income (419)	102,462	175,143		
38	Allowance for other funds used during construction (419.1)	3,179,824	2,786,095		
39	Miscellaneous nonoperating income (421)	24,363,808	41,487,372		
40	Gain on disposition of property (421.1)	-	-		
41	Total other income (enter total of lines 31 through 40)	28,222,504	46,409,375	-	-
42	Other income deductions				
43	Loss on disposition of property (421.2)	-	(16,095)		
44	Miscellaneous Amortization (425)	-	-		
45	Donations (426.1)	369,917	527,792		
46	Life insurance (426.2)	-	-		
47	Penalties (426.3)	4,960	108		
48	Expenditures for certain civic, political, and related activities (426.4)	152,947	117,856		
49	Other deductions (426.5)	21,068,799	38,074,113		
50	Total other income deductions (total of lines 43 through 49)	21,596,623	38,703,774	-	-
51	Taxes applic. to other income and deductions				
52	Taxes other than income taxes (408.2)	7,231	1,861		
53	Income taxes - federal (409.2)	431,401	1,970,636		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 12/31/2009	2009/Q4

FOOTNOTE DATA

54	Income taxes - other (409.2)	362,377	369,003		
55	Provision for deferred income taxes (410.2)	1,277,591	2,202,238		
56	(Less) Provision for deferred income taxes - credit (411.2)	1,053,808	2,375,103		
57	Investment tax credit adj. - net (411.5)	(673)	(673)		
58	(Less) Investment Tax Credits (420)	-	-		
59	Total Taxes on other income and deductions (total of lines 52-58)	1,024,119	2,167,962	-	-
60	Net other income and deductions (total of lines 41,50,59)	5,601,762	5,537,639	-	-
61	Interest charges				
62	Interest on long-term debt (427)	18,612,462	12,794,101		
63	Amortization of debt disc. and expense (428)	1,107,267	144,490		
64	Amortization of loss on reacquired debt (428.1)	306,279	387,973		
65	(Less) Amort. Of Premium on Debt-Credit (429)	-	-		
66	(Less) Amortization of gain on reacquired debt - credit (429.1)	-	89		
67	Interest on debt to assoc. companies (430)	-	-		
68	Other interest expense (431)	423,796	1,261,103		
69	(Less) Allowance for borrowed funds used during construction - credit (432)	1,036,181	1,692,397		
70	Net interest charges (total of lines 62 through 69)	19,413,623	12,895,181	-	-
71	Income Before Extraordinary Items (Totals of lines 27, 60 and 70)	34,078,812	33,233,958	-	-
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)	-	-	-	-
77	Extraordinary items after taxes (line 75 less line 76)	-	-	-	-
78	Net Income (Enter Total of lines 71 & 77)	$ 34,078,812	$ 33,233,958	$ -	$ -

Page 117 - Footnote

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		125,764,812	106,972,504
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)		34,078,812	22,131,041
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess hydro licensing amortization		-32,258	(28,575)
19	Storm reserve required by First Mortgage Bond Indenture			
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-32,258	(28,575)
23	Dividends Declared-Preferred Stock (Account 437)			
24	$3.60 Preferred $216,000		-108,000	(216,000)
25	$4.40 Preferred $110,000		-55,000	(110,000)
26	$4.65 Preferred $136,500		-69,750	(139,500)
27	$6.75 Preferred $270,000		-134,999	(270,000)
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-367,749	(735,500)
30	Dividends Declared-Common Stock (Account 438)			
31			-33,845,744	(37,357,163)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-33,845,744	(37,357,163)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			7,471,433
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		125,597,873	98,453,740
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39	Amortization reserved, federal (Account 215.1)		230,867	198,609
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		230,867	198,609
	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)		230,867	198,609
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		125,828,740	98,652,349
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			156,189,175
50	Equity in Earnings for Year (Credit) (Account 418.1)			12,993,570
51	(Less) Dividends Received (Debit)			7,471,433
52				
53	Balance-End of Year (Total lines 49 thru 52)			161,711,312

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

Schedule Page: 118 Line No.: 1 Column: c

On July 1, 2009 Otter Tail Power Company, 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 (formerly known as Otter Tail Holding Company). This footnote shows how pages 118-119 would have been prepared if Otter Tail Power Company had been a wholly owned subsidiary in 2008.

Otter Tail Power Company — **End of 2009/Q4**

STATEMENT OF RETAINED EARNINGS

Line No.	Item	Current Quarter/Year Year to Date Balance	Previous Quarter/Year Year to Date Balance
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance - beginning of year	$ 125,764,812	$ 123,180,658
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 (Account 439)		
16	Balance transferred from income (Account 433 less account 418.1)	34,078,812	33,233,958
17	Appropriations of retained earnings (Account 436)		
18	Excess hydro licensing amortization	(32,258)	(28,575)
19			
20			
21			
22	Total appropriations of retained earnings (Account 436)	(32,258)	(28,575)
23	Dividends declared - preferred stock (Account 437)		
24	$3.60 Preferred $216,000	(108,000)	(216,000)
25	$4.40 Preferred $110,000	(55,000)	(110,000)
26	$4.65 Preferred $139,500	(69,750)	(139,500)
27	$6.75 Preferred $270,000	(134,999)	(270,000)
28			
29	Total dividends declared - preferred stock (Account 437)	(367,749)	(735,500)
30	Dividends declared - common stock (Account 438)		
31		(33,845,744)	(29,885,729)
32			
33			
34			
35			
36	Total Dividends declared - common stock (Account 438)	(33,845,744)	(29,885,729)
37	Transfers from Acct 216.1, unapprop. undistrib. subsidiary earnings		
38	Balance - end of period (total 1,9,15,16,22,29,36,37)	125,597,873	125,764,812
	APPROPRIATED RETAINED EARNINGS (ACCOUNT 215)		
39	Amortization reserve, federal (Account 215.1)	230,867	198,610
40			
41			
42			
43			
44			
45	TOTAL Appropriated Retained Earnings (Account 215)	230,867	198,610

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 12/31/2009	2009/Q4

FOOTNOTE DATA

	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)	230,867	198,610
48	Total Retained Earnings (Accounts 215, 215.1, 216) (Total 38,47) (216.1)	$ 125,828,740	$ 125,963,422
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)		
	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 through 52)		

Pages 118-119 Footnotes

Name of Respondent Otter Tail Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	34,078,812	35,124,611
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	34,997,778	30,351,414
5	Amortization	1,755,271	715,755
6			
7			
8	Deferred Income Taxes (Net)	31,067,666	16,066,994
9	Investment Tax Credit Adjustment (Net)	13,372,472	17,526,195
10	Net (Increase) Decrease in Receivables	26,379,736	-30,643,502
11	Net (Increase) Decrease in Inventory	-1,072,801	-441,330
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	1,270,706	-32,296,278
14	Net (Increase) Decrease in Other Regulatory Assets	-34,596,027	-43,831,706
15	Net Increase (Decrease) in Other Regulatory Liabilities	-626,837	771,692
16	(Less) Allowance for Other Funds Used During Construction	3,179,824	2,786,095
17	(Less) Undistributed Earnings from Subsidiary Companies		5,522,137
18	Other: (Increase) decrease in noncurrent assets and deferred debits	-1,744,046	1,183,784
19	Other: Increase (decrease) in noncurrent liabilities & deferred credit	8,595,459	38,967,378
20	Other: (Increase) decrease in other current assets	-40,130,593	12,828,481
21	Other: Losses on investments in non current assets		393,126
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	70,167,772	38,408,382
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-133,706,519	-177,657,553
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	125,960	-411,643
30	(Less) Allowance for Other Funds Used During Construction	-3,179,824	-2,786,095
31	Other (provide details in footnote):		
32	Other: 2009 American Recovery and Reinvestment Act Grant	30,182,104	
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-100,218,631	-175,283,101
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		-30,630,221
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)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other: Decrease in funds on deposit with trustee	600,854	54,492
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-99,617,777	-205,858,830
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	99,400,000	
62	Preferred Stock		
63	Common Stock	9,669,028	166,937,248
64	Other: Payments for debt issuance expense	-4,369,919	-462,312
65			
66	Net Increase in Short-Term Debt (c)		27,064,471
67	Other: Capital stock expense		-6,417,998
68	Other: Checks issued in excess of cash	1,708,112	
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	106,407,221	187,121,409
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-17,265,000	-2,428,572
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)	-25,479,147	
79			
80	Dividends on Preferred Stock	-367,749	-735,500
81	Dividends on Common Stock	-33,845,744	-37,357,163
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	29,449,581	146,600,174
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-424	-20,850,274
87			
88	Cash and Cash Equivalents at Beginning of Period	30,432	27,304,128
89			
90	Cash and Cash Equivalents at End of period	30,008	6,453,854

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) _ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

Schedule Page: 120 Line No.: 2 Column: b

On July 1, 2009 Otter Tail Power Company, 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 (formerly known as Otter Tail Holding Company). This footnote shows how pages 120-121 would have been prepared if Otter Tail Power Company had been a wholly owned subsidiary in 2008.

Otter Tail Power Company **End of 2009/Q4**

STATEMENT OF CASH FLOWS

Line No.	Description	Current Year to Date Quarter/Year	Previous Year to Date Quarter/Year
1	Net cash flow from operating activities:		
2	Net income (Line 78c on page 117)	$ 34,078,812	$ 33,233,958
3	Noncash charges (credits) to income:		
4	Depreciation and depletion	34,997,778	29,817,328
5	Amortization	1,755,271	860,245
6			
7			
8	Deferred income taxes (net)	31,067,666	16,072,716
9	Investment tax credit adjustment (net)	13,372,472	17,526,196
10	Net (increase) decrease in receivables	26,379,736	(23,771,237)
11	Net (increase) decrease in inventory	(1,072,801)	(441,331)
12	Net (increase) decrease in allowances inventory	-	-
13	Net increase (decrease) in payables and accrued expenses	1,270,706	(29,435,699)
14	Net (increase) decrease in other regulatory assets	(34,596,027)	(43,831,707)
15	Net increase (decrease) in other regulatory liabilities	(626,837)	771,692
16	(Less) allowance for other funds used during construction	3,179,824	2,786,095
17	(Less) undistributed earnings from subsidiary companies	-	-
18	Other: (increase) decrease in noncurrent assets and deferred debits	(1,744,046)	786,253
19	Other: increase (decrease) in noncurrent liabilities and deferred credits	8,595,459	43,011,671
20	Other: (Increase) decrease in other current assets	(40,130,593)	12,838,414
21			
22	Net cash provided by (used in) operating activities (total 2 through 21)	70,167,772	54,652,404
23			
24	Cash flows from investment activities:		
25	Construction and acquisition of plant (including land):		
26	Gross additions to utility plant (less nuclear fuel)	(133,706,519)	(177,657,553)
27	Gross additions to nuclear fuel		
28	Gross additions to common utility plant		
29	Gross additions to nonutility plant	125,960	(177,759)
30	(Less) allowance for other funds used during construction	(3,179,824)	(2,786,095)
31	Other (provide details in footnote):		
32	Other: 2009 American Recovery and Reinvestment Act Grant	30,182,104	
33			
34	Cash outflows for plant (total of lines 26 through 33)	(100,218,631)	(175,049,217)
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 sudsidiary 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)		

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Otter Tail Power Company **End of 2009/Q4**

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

STATEMENT OF CASH FLOWS (Continued)

Line No.	Description	Current Year to Date Quarter/Year	Previous Year to Date Quarter/Year
46	Loans made or purchased		
47	Collections on loans		
48			
49	Net (increase) decrease in receivables		
50	Net (increase) decrease in inventory		
51	Net (increase) decrease in allowances held for speculation		
52	Net increase (decrease) in payables and accrued expenses		
53	Other: (increase) decrease in funds on deposit with trustee	600,854	264,491
54			
55			
56	Net cash provided by (used in) investing activities		
57	(Total of lines 34 through 55)	(99,617,777)	(174,784,726)
58			
59	Cash flows from financing activities:		
60	Proceeds from issuance of:		
61	Long-term debt (b)	99,400,000	57,000,000
62	Preferred stock		
63	Common stock	9,669,028	45,610,190
64	Other: (Increase) Decrease in Unamortized Debt Expense	(4,369,919)	(1,117,156)
65			
66	Net increase in short-term debt (c)		27,064,471
67	Other: change in checks written in excess of cash	1,708,112	(154,729)
68			
69			
70	Cash provided by outside sources (total 61 through 69)	106,407,221	128,402,776
71			
72	Payments for retirement of:		
73	Long-term debt (b)	(17,265,000)	(100,000)
74	Preferred stock		
75	Common stock		
76	Other (provide details in footnote):		
77			
78	Net decrease in short-term debt (c)	(25,479,147)	
79			
80	Dividends on preferred stock	(367,749)	(735,500)
81	Dividends on common stock	(33,845,744)	(29,885,730)
82	Net cash provided by (used in) financing activities		
83	(Total of lines 70 through 81)	29,449,581	97,681,546
84			
85	Net increase (decrease) in cash and cash equivalents		
86	(Total of lines 22, 57, and 83)	(424)	(22,450,776)
87			
88	Cash and cash equivalents at beginning of period	30,432	22,481,208
89			
90	Cash and cash equivalents at end of period	$ 30,008	$ 30,432

Page 121- Footnotes

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,

Name of Respondent Otter Tail Power Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report 2009/Q4

FOOTNOTE DATA

miscellaneous deferred debits, 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.: 21 Column: a

Loss on affordable housing investments.

Schedule Page: 120 Line No.: 32 Column: a

Federal grant received for the Luverne Wind Farm.

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

Expenses related to capital stock issuance, including legal costs, registration fees, underwriters fees, and offering fees.

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

Change in checks written in excess of cash.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

NOTES TO FINANCIAL STATEMENTS

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

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

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.

	2009	2008
Cash Equivalents	$ 0	$ 0

Reconciliation	2009	2008
Cash – Account 131 (Line 35, Page 110)	$ 9,403	$ 7,902
Working Fund – Account 135 (Line 37, Page 110)	20,605	22,530
Cash Equivalent – Account 136 (Above)	0	0
	$ 30,008	$ 30,432

Otter Tail Power Company
Notes to Financial Statements
For the years ended December 31, 2009 and 2008

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 (formerly known as Otter Tail Holding Company). 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 Midwest Independent Transmission System Operator (MISO) markets.

OTP provides electricity to more than 129,000 customers in a 50,000 square mile area of Minnesota, North Dakota and 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 423 communities and adjacent rural areas and farms, approximately 130,900 people live in communities having a population of more than 1,000, according to the 2000 census. The only communities served which have a population in excess of 10,000 are Jamestown, North Dakota (15,527); Fergus Falls, Minnesota (13,471); and Bemidji, Minnesota (11,917). As of December 31, 2009, OTP served 129,307 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:

(in thousands)	2009	2008
Accounts Receivable	$91	$209
Accounts Payable	1,055	1,078
Long-Term Debt	15,500	256,790
Operating Revenues	201	294
Other Operation and Maintenance Expenses	8,124	7,631

The related party transactions predominately relate to electric sales to operating subsidiaries of Otter Tail Corporation and to the allocation of corporate overhead expenses, insurance premiums 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 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 depreciation 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.

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 (AFUDC). The amount of AFUDC on electric utility plant was $4,216,000 in 2009 and $4,478,000 in 2008. 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, a regulatory liability. Maintenance, repairs and replacement of minor items of property are charged to operating expenses. The provisions for utility depreciation for financial reporting purposes are made on the straight-line method based on the estimated service lives of the properties. Such provisions as a percent of the average balance of depreciable electric utility property were 2.90% in 2009 and 2.81% in 2008. Gains or losses on group asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Jointly Owned Plants

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, 2009 and 2008 balance sheets:

(in thousands)	2009	2008
Big Stone Plant:		
Electric Plant in Service	$ 135,500	$ 135,623
Accumulated Depreciation	(78,306)	(74,416)
Net Plant	$ 57,194	$ 61,207
Coyote Station:		
Electric Plant in Service	$ 155,417	$ 148,109
Accumulated Depreciation	(87,269)	(86,911)
Net Plant	$ 68,148	$ 61,198

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

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
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. OTP amortizes investment tax credits over the estimated lives of related property. OTP records income taxes in accordance with ASC 740, *Income Taxes*, and has recognized in its financial statements the tax effects of all tax positions that are "more-likely-than-not" to be sustained on audit based solely on the technical merits of those positions as of the balance sheet date. The term "more-likely-than-not" means a likelihood of more than 50%. OTP classifies interest and penalties on tax uncertainties as components of the provision for income taxes. See note 11 to the financial statements regarding OTP’s accounting for uncertain tax positions.

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 (FCA), 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 accrued for fuel and purchased power costs incurred in excess of amounts recovered in base rates but not yet billed through the FCA and for renewable resource 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 815-10-45-9. 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 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, *Derivatives and Hedging*, 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 revenues, accrued renewable resource and transmission 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.

Supplemental Disclosures of Cash Flow Information

(in thousands)	2009	2008
Decreases in Accounts Payable and Other Liabilities Related to Capital Expenditures	$ (1,130)	$(21,067)
Noncash Financing Transaction:		
Preferred Stock Exchanged for Notes Payable to Parent – July 1, 2009	$ 15,500	$ --
Cash Paid During the Year for:		
Interest (net of amount capitalized)	$ 17,971	$ 13,943
Income Tax (Refunds)	$(20,527)	$ (808)

Investments
The following table provides a breakdown of OTP's investments at December 31, 2009 and 2008:

(in thousands)	December 31, 2009	December 31, 2008
Cost Method:		
Economic Development Loan Pools	$ 482	$ 528
Other	16	514
Equity Method:		
Partnerships	17	17
Total Investments	$ 515	$ 1,059

Fair Value Measurements
Effective January 1, 2008, OTP adopted ASC 820, *Fair Value Measurements and Disclosures*, for recurring fair value measurements. ASC 820 provides a single definition of fair value and requires enhanced disclosures about assets and liabilities measured at fair value. ASC 820-10-35 establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the hierarchy and examples of each level are as follows:

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

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

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

The following tables present, for each of these hierarchy levels, OTP's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2009 and 2008:

2009 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Forward Energy Contracts	$ --	$ 8,321	$ --
Liabilities:			
Forward Energy Contracts	--	$ 14,681	--
Net Assets (Liabilities)	$ --	$ (6,360)	$ --

2008 *(in thousands)*	Level 1	Level 2	Level 3
Assets:			
Forward Energy Contracts	$ --	$ 405	$ --
Liabilities:			
Forward Energy Contracts	--	$ 1,690	--
Net Assets (Liabilities)	$ --	$ (1,285)	$ --

Inventories

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

New Accounting Standards

Disclosures about Derivative Instruments and Hedging Activities—In March 2008, the FASB issued new guidance on disclosures about derivative instruments and hedging activities. The new guidance under ASC 815, *Derivatives and Hedging,* requires enhanced disclosures about an entity's derivative and hedging activities to improve the transparency of financial reporting and is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. OTP adopted the new guidance on January 1, 2009. Adoption of the new guidance resulted in additional footnote disclosures related to OTP's use of derivative instruments, the location and fair value of derivatives reported on OTP's balance sheets, the location and amounts of derivative instrument gains and losses reported on OTP's statements of income and information on credit risk exposure related to derivative instruments.

Employers' Disclosures about Postretirement Benefit Plan Assets—In December 2008, the FASB issued new guidance on Employers' Disclosures about Pensions and Other Postretirement Benefits. The new guidance under ASC 715-20 *Defined Benefit Plans—General,* expands an employer's required disclosures about plan assets of a defined benefit pension or other postretirement plan to include investment policies and strategies, major categories of plan assets, information regarding fair value measurements, and significant concentrations of credit risk. The new guidance is effective for fiscal years ending after December 15, 2009. (See note 8 to financial statements.)

Interim Disclosures about Fair Value of Financial Instruments—In April 2009, the FASB issued new guidance on disclosures about fair value of financial instruments to require disclosures regarding the fair value of financial instruments in interim financial statements. The new disclosure requirements under ASC 825, *Financial Instruments,* are effective for interim periods ending after June 15, 2009. OTP implemented the new guidance on April 1, 2009. The implementation did not have a material impact on OTP's financial statements. ASC 825 required disclosures have been included in OTP's notes to financial statements, where applicable.

Subsequent Events—In May 2009, the FASB issued new guidance regarding subsequent events. The new guidance under ASC 855, *Subsequent Events,* establishes general standards of accounting and disclosure for events that occur after the balance sheet date but before financial statements are issued. The new accounting guidance is consistent with the auditing literature widely used for accounting and disclosure of subsequent events, however, the new guidance requires an entity to disclose the date through which subsequent events have been evaluated. The new guidance is effective for interim and annual periods ending after June 15, 2009. OTP implemented the new guidance on April 1, 2009. The implementation did not have a material impact on OTP's financial statements. OTP has evaluated events occurring through March 19, 2010 and determined there are no events that would have occurred subsequent to December 31, 2009 that would affect OTP's financial statements as of, and for the periods ending December 31 2009 or that require disclosure in this report.

2. Rate and Regulatory Matters

Minnesota

General Rate Case--In an order issued by the Minnesota Public Utilities Commission (MPUC) on August 1, 2008 OTP was granted an increase in Minnesota retail electric rates of $3.8 million, or approximately 2.9%, which went into effect in February 2009. The MPUC approved a rate of return on equity of 10.43% on a capital structure with 50.0% equity. An interim rate increase of 5.4% was in effect from November 30, 2007 through January 31, 2009. Amounts refundable totaling $3.9 million had been recorded as a liability on

OTP's balance sheet as of December 31, 2008. An additional $0.5 million refund liability was accrued in January 2009. OTP refunded Minnesota customers the difference between interim and final rates, with interest, in March 2009. In June 2008, OTP deferred recognition of $1.5 million in rate case-related regulatory assessments and fees of outside experts and attorneys that are subject to amortization and recovery over a three-year period beginning in February 2009.

Capacity Expansion 2020 (CapX 2020) Mega Certificate of Need (CON)--On August 16, 2007 the eleven CapX 2020 utilities asked the MPUC to determine the need for three 345-kilovolt (kV) transmission lines. Evidentiary hearings for the CON for the three CapX 2020 345-kV transmission line projects began in July 2008 and continued into August 2008. On April 16, 2009 the MPUC approved the CON for the three 345-kV Group 1 CapX 2020 line projects (Fargo-St. Cloud, Brookings-Southeast Twin Cities, and Twin Cities-LaCrosse). The MPUC then voted to impose conditions pertaining to reserving line capacity for renewable energy sources on the Brookings line project. The MPUC did take up reconsideration of the original order regarding the conditions. The MPUC slightly modified the conditions on the Brookings line. As part of the CON approval, the MPUC accepted a CapX 2020 request to build the 345-kV lines for double-circuit capability to have two 345-kV transmission circuits on each structure. The current plan is to string only one circuit. The MPUC CON orders were appealed to the Minnesota Court of Appeals on October 9, 2009 and the appellate court's determination is expected to be made in the fall of 2010. Route permit applications were filed in Minnesota for the Brookings project in late December 2008. The route permit for the Monticello to St. Cloud portion of the Fargo project was filed in April 2009 and is anticipated to be received in mid-2010. The Minnesota route permit for the St. Cloud to Fargo portion of the Fargo Project was filed on October 1, 2009. Portions of the projects would also require approvals by federal officials and by regulators in North Dakota, South Dakota and Wisconsin. After regulatory need is established and routing decisions are completed, construction will begin. The lines would be expected to be completed over a period of two to four years. Great River Energy and Xcel Energy are leading these projects, and OTP and eight other utilities are involved in permitting, building and financing. OTP is directly involved in two of these three 345-kV projects.

OTP serves as the lead utility in a fourth CapX 2020 Group 1 project, the Bemidji-Grand Rapids 230-kV line, which has an expected in-service date of 2012-2013. OTP filed an application for a CON for this fourth project on March 17, 2008. The Department of Commerce Office of Energy Security (MNOES) staff completed briefing papers regarding the Bemidji-Grand Rapids route permit application. The MNOES staff recommended to the MPUC that: (1) the route permit application be found to be complete, (2) the need determination not be sent to a contested case but be handled informally by MPUC review, and (3) the CON and route permit proceedings be combined as requested. The MPUC met on June 26, 2008 to act on the MNOES staff recommendation. The MPUC agreed that the CON and route permit applications were complete. The MNOES subsequently recommended a determination that need for the line has been established. An environmental report for the CON was issued in April 2009. CON hearings were conducted on May 20 and May 21, 2009 and a summary of comments was issued on June 8, 2009. The CON was issued on July 9, 2009 and the written order received on July 14, 2009. The applicants continue to work with the MNOES to define the schedule for issuance of the draft environmental impact statement (EIS) and the route contested case hearing. The route hearing is expected to occur in early 2010. The MPUC is expected to determine the route for this line and, if appropriate, issue a route permit in fall 2010. A federal EIS also will be needed for this project.

Renewable Energy Standards, Conservation and Renewable Resource Riders--In February 2007, the Minnesota legislature passed a renewable energy standard requiring 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: 12% by 2012; 17% by 2016; 20% by 2020 and 25% by 2025. Additionally, Minnesota law requires utilities to make a good faith effort to generate or procure sufficient renewable generation such that 7% of total retail electric sales to retail customers in Minnesota come from qualifying renewable sources by 2010. 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 has sufficient renewable energy resources available and in service to comply with the required 2016 level of 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 standards. 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 now 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.

In an order issued on August 15, 2008, the MPUC approved OTP's proposal to implement a Renewable Resource Cost Recovery Rider for its Minnesota jurisdictional portion of investment in qualifying renewable energy facilities. The rider enables OTP to recover from its Minnesota retail customers its investments in owned renewable energy facilities and provides for a return on those investments. The Minnesota Renewable Resource Adjustment (MNRRA) of $0.0019 per kilowatt-hour (kwh) was included on Minnesota customers' electric service statements beginning in September 2008, reflecting cost recovery for OTP's twenty-seven 1.5 megawatt (MW) wind turbines and collector system at the Langdon Wind Energy Center, which became fully operational in January 2008.

The MPUC approved OTP's petition for a 2009 MNRRA in July 2009, which increased the MNRRA rate to provide cost recovery for its 32 wind turbines at the Ashtabula Wind Energy Center that became commercially operational in November 2008. This approval increased the 2009 MNRRA to $0.00415 per kwh for the recovery of $6.6 million through March 31, 2010--$4.0 million from August through December 2009 and $2.6 million from January through March 2010 The approval also granted OTP authority to recover over a 48-month period beginning in April 2010 accrued renewable resource recovery revenues that had not previously been recovered. OTP has recognized a regulatory asset of $5.3 million for revenues that are eligible for recovery through the rider but have not been billed to Minnesota customers as of December 31, 2009. On January 12, 2010, the MPUC issued an order finding OTP's Luverne Wind Farm project eligible for cost recovery through the MNRRA. The 2010 annual MNRRA cost recovery filing was made on December 31, 2009 with a requested effective date of April 1, 2010.

In addition to the Renewable Resource Cost Recovery 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 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 otherwise deemed eligible by the MPUC. Such transmission cost recovery riders allow a return on investments at the level approved in a utility's last general rate case. Additionally, following approval of the rate schedule, the MPUC may approve annual rate adjustments filed pursuant to the rate schedule. OTP's request for approval of a transmission cost recovery rider was granted by the MPUC on January 7, 2010, and became effective February 1, 2010. Beginning February 1, 2010, OTP's transmission rider rate is reflected on Minnesota customer electric service statements at $0.00039 per kwh plus $0.035 per kW for large general service customers and $0.00007 per kwh for controlled service customers, $0.00025 per kwh for lighting customers, and $0.00057 per kwh for all other customers. As of December 31, 2009 OTP had accrued $0.4 million in revenues that are eligible for recovery through the rider but have not been billed.

<u>Recovery of MISO Costs</u>--In an order issued on December 20, 2006 the MPUC stated that except for schedule 16 and 17 administrative costs, discussed below, each petitioning utility may recover the charges imposed by the MISO for MISO Day 2 operations (offset by revenues from Day 2 operations via net accounting) through the calculation of the utility's FCA from the period April 1, 2005 through a period of at least three years after the date of the order. The MPUC also ordered the utilities to refund schedule 16 and 17 costs collected through the FCA since the inception of MISO Day 2 Markets in April 2005 and stated that each petitioning utility may use deferred accounting for MISO schedule 16 and 17 costs incurred since April 1, 2005. This deferred accounting may continue for ongoing schedule 16 and 17 costs, without the accumulation of interest, until the earlier of March 1, 2009 or the utility's next electric rate case. Pursuant to this December 20, 2006 order, OTP was ordered to refund $446,000 in MISO schedule 16 and 17 costs to Minnesota retail customers through the FCA over a twelve-month period beginning in January 2007. OTP requested recovery of the deferred costs and recovery of the ongoing costs in its general rate case filed in October 2007 and began amortizing its deferred MISO schedule 16 and 17 costs over a 35-month period in January 2008. The remaining unamortized balance was $252,000 as of December 31, 2009. The August 1, 2008 MPUC Order in the general rate case allowed future recovery of MISO schedule 16 and 17 costs and recovery of the deferred Schedule 16 and 17 costs.

<u>Minnesota Annual Automatic Adjustment Report on Energy Costs (AAA Report)</u>--The MNDOC and OTP identified two operational situations which are not covered in the approved method for allocating MISO costs contained in the final December 20, 2006 MPUC order discussed above. One relates to plants not expected to be available for retail but that produce energy in certain hours, resulting in wholesale sales. The other situation is related to Financial Transmission Rights (FTRs) not needed for retail load. For the period July 1, 2005 through June 30, 2007 OTP determined its Minnesota customers' portion of costs associated with these situations to be

$765,000. The data was provided to the MNDOC during the course of the MNDOC's review of the AAA Report. OTP offered to refund $765,000 to its Minnesota customers to settle this and other issues raised by the MNDOC in the AAA Report docket before the MPUC and the MNDOC accepted the offer in October 2007 and recommended that the MPUC include the refund in its final order. OTP also agreed to modifications to the MISO Day 2 cost allocations that were resolved in the MPUC's December 20, 2006 order. OTP agreed to make some of those modifications retroactive back to January 1, 2007. The MPUC accepted OTP's refund offer and modifications and closed this docket on February 6, 2008. In December 2007, OTP recorded a liability and a reduction to revenue of $805,000 for the amount of the refund offer and similar revenues collected subsequent to June 30, 2007. Refunds to Minnesota customers were completed during 2008.

North Dakota

General Rate Case--On November 3, 2008 OTP filed a general rate case in North Dakota requesting an overall revenue increase of approximately $6.1 million, or 5.1%, and an interim rate increase of approximately 4.1%, or $4.8 million annualized, that went into effect on January 2, 2009. In an order issued by the North Dakota Public Service Commission (NDPSC) on November 25, 2009 OTP was granted an increase in North Dakota retail electric rates of $3.6 million or approximately 3.0%, which went into effect in December 2009. The NDPSC order authorizing an interim rate increase requires OTP to refund North Dakota customers the difference between final and interim rates, with interest. OTP established a refund reserve for revenues collected under interim rates that exceeded the final rate increase. The refund reserve balance was $0.9 million as of December 31, 2009, which will be refunded to North Dakota customers in January 2010. OTP deferred recognition of $0.5 million in rate case-related filing and administrative costs that are subject to amortization and recovery over a three year period beginning in January 2010.

Renewable Resource Cost Recovery Rider--On May 21, 2008 the NDPSC approved OTP's request for a Renewable Resource Cost Recovery Rider to enable OTP to recover the North Dakota share of its investments in renewable energy facilities it owns in North Dakota. The North Dakota Renewable Resource Cost Recovery Rider Adjustment (NDRRA) of $0.00193 per kwh was included on North Dakota customers' electric service statements beginning in June 2008, and reflects cost recovery for OTP's twenty-seven 1.5 MW wind turbines and collector system at the Langdon Wind Energy Center, which became fully operational in January 2008. The rider also allows OTP to recover costs associated with other new renewable energy projects as they are completed. OTP included investment costs and expenses related to its 32 wind turbines at the Ashtabula Wind Energy Center that became commercially operational in November 2008 in its 2009 annual request to the NDPSC to increase the amount of the NDRRA. An NDRRA of $0.0051 per kwh was approved by the NDPSC on January 14, 2009 and went into effect beginning with billing statements sent on February 1, 2009.

In a proceeding that was combined with OTP's general rate case, the NDPSC reviewed whether to move the costs of the projects currently being recovered through the NDRRA into base rate cost recovery and whether to make changes to the rider. A settlement of the general rate case and the NDRRA reduced the NDRRA to $0.00369 for the period from December 1, 2009 until the effective date for the next annual NDRRA filing, requested to be April 1, 2010. Because the 2008 annual NDRRA filing was combined with the general rate case proceedings (concluded in November 2009), the 2009 annual filing to establish the 2010 NDRRA rate (which includes cost recovery for OTP's investment in its Luverne Wind Farm project) was delayed until December 31, 2009, with a requested effective date of April 1, 2010.

OTP had not been deferring recognition of its renewable resource costs eligible for recovery under the NDRRA but had been charging those costs to operating expense since January 2008. After approval of the rider in May 2008, OTP accrued revenues related to its investment in renewable energy and for renewable energy costs incurred since January 2008 that are eligible for recovery through the NDRRA. Terms of the approved settlement provide for the recovery of accrued but unbilled NDRRA revenues over a period of 48 months beginning in January 2010. OTP's December 31, 2009 balance sheet includes a regulatory asset of $0.6 million for revenues that are eligible for recovery through the NDRRA but have not been billed to North Dakota customers.

North Dakota legislation also 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 requested recovery of such costs in its general rate case filed in November 2008, and was granted recovery of such costs by the NDPSC in its November 25, 2009 order.

<u>CapX 2020 Request for Advance Determination of Prudence</u>--On October 5, 2009 OTP filed an application for an advance determination of prudence with the NDPSC for its proposed participation in three of the four Group 1 projects (Fargo-St. Cloud, Brookings-Southeast Twin Cities, and Bemidji-Grand Rapids). An administrative law judge has been assigned to conduct a hearing that is currently scheduled for April 2010.

<u>Recovery of MISO Costs</u>--In February 2005, OTP filed a petition with the NDPSC to seek recovery of certain MISO-related costs through the FCA. The NDPSC granted interim recovery through the FCA in April 2005, but similar to the decision of the MPUC, conditioned the relief as being subject to refund until the merits of the case are determined. In August 2007, the NDPSC approved a settlement agreement between OTP and an intervener representing several large industrial customers in North Dakota. Under the approved settlement agreement, OTP refunded $493,000 of MISO schedule 16 and 17 costs collected through the FCA from April 2005 through July 2007 to North Dakota customers beginning in October 2007 and ending in January 2008. OTP deferred recognition of these costs plus $330,000 in MISO schedule 16 and 17 costs incurred from August 2007 through December 2008 and requested recovery of these deferred costs in its general rate case filed in North Dakota in November 2008. OTP began amortizing its deferred MISO schedule 16 and 17 costs in North Dakota over a 36-month period beginning in December 2009 in conjunction with the implementation of rates approved by the NDPSC in its November 25, 2009 order. As of December 31, 2009 the balance of OTP's deferred MISO schedule 16 and 17 costs was $1,091,000. Base rate recovery for on-going MISO schedule 16 and 17 costs was also approved by the NDPSC in its November 25, 2009 order.

<u>South Dakota</u>

<u>General Rate Case</u>--On October 31, 2008 OTP filed a general rate case in South Dakota requesting an overall revenue increase of approximately $3.8 million, or 15.3%, which included, among other things, recovery of investments and expenses related to renewable resources in base rates. OTP increased rates by approximately 11.7% on a temporary basis beginning with electricity consumed on and after May 1, 2009, as allowed under South Dakota law. In an order issued by the South Dakota Public Utilities Commission (SDPUC) on June 30, 2009, OTP was granted an increase in South Dakota retail electric rates of $2.9 million or approximately 11.7%. OTP implemented final, approved rates in July 2009.

<u>Federal</u>

<u>Revenue Sufficiency Guarantee (RSG) Charges</u>--Since 2006, OTP has been a party to litigation before the FERC regarding the application of RSG charges to market participants who withdraw energy from the market or engage in financial-only, virtual sales of energy into the market or both. These litigated proceedings occurred in several electric rate and complaint dockets before the FERC and several of the FERC's orders are on review before the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit).

On November 7, 2008 the FERC issued an order on rehearing and compliance in the RSG proceeding, reversing its determination in a prior order and stating that MISO should remove the volume of virtual supply offers of market participants—not physically withdrawing energy—from the denominator of the rate calculation from April 25, 2006 forward. MISO interpreted the order to mean that all virtual supply offers and deviations in the denominator of the rate calculation that do not ultimately pay the rate should be removed from April 1, 2005 (start of the Energy Market) forward. On November 10, 2008 the FERC issued an order finding the current RSG rate unjust and unreasonable and accepting an interim rate that applied RSG charges to all virtual sales until such time as MISO makes a subsequent filing of the new RSG rate.

On May 6, 2009 the FERC issued an order on rehearing of the November 10, 2008 order. The May order relieved MISO from having to resettle RSG payments resulting from the FERC's earlier decision to remove the words "actually withdraws energy" (AWE) from the RSG tariff provisions. Absent this relief (or waiver), the removal of the AWE language would have had two relevant impacts on the RSG charge: (1) it would tend to reduce the RSG rate because the rate denominator would include all virtual supply volumes and (2) it would impose RSG charges on all cleared virtual supply transactions. The waiver applies to the period August 10, 2007 through November 9, 2008. Beginning November 10, 2008, the MISO is obliged to resettle RSG charges by recalculating the RSG rate and impose RSG charges on all virtual supply transactions.

On June 12, 2009 the FERC issued an order on rehearing of the November 7, 2008 order. The June order, at a minimum, relieved MISO from having to resettle RSG payments resulting from any difference between the megawatt hours associated with virtual supply in the denominator of the RSG rate and the billing determinants associated with virtual supply transactions (VSO mismatch). This relief (or waiver) applies to the period April 25, 2006 through November 4, 2007. Since OTP would have had a payment obligation during this period associated with the virtual supply and other mismatches, the June order eliminates that payment obligation. However, the June order, like many of the other orders in this docket, is subject to appellate review and potential reversal. Beginning from November 5, 2007, MISO is obligated to resettle to correct the VSO mismatch. As of September 30, 2009, OTP had paid all its resettlement obligations determined and imposed by MISO. On August 7, 2009 the FERC issued an order requiring MISO's RSG Task Force to develop a recommendation on any transactions that should be exempted from paying RSG charges. The RSG Task Force has completed its review and provided recommendations to the FERC. OTP does not know when these litigation proceedings will conclude.

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, due to a number of factors. The broad economic downturn, a high level of uncertainty associated with proposed federal climate legislation and existing federal environmental regulations and challenging credit and equity markets made proceeding with Big Stone II and committing to approximately $400 million in capital expenditures untenable for OTP's customers and OTP's shareholders. On November 2, 2009, the remaining Big Stone II participants announced the cancellation of the Big Stone II project.

As of December 31, 2009, OTP had incurred $13.0 million in costs related to this project that it believes are probable of recovery in future rates and has deferred recognition of these costs as operating expenses pending determination of recoverability by the state and federal regulatory commissions that approve OTP's rates. In filings made on December 14, 2009, OTP requested from its three state commissions authority to reflect these costs on its books as a regulatory asset through the use of deferred accounting, pending a determination on the recoverability of the costs. The SDPUC approved OTP's request for deferred accounting treatment on February 9, 2010. If Minnesota or North Dakota denies the requests to use deferred accounting or if any of the three jurisdictions eventually denies recovery of all or any portion of these deferred costs, such costs would be subject to expense in the period they are deemed to be inappropriate for deferral or unrecoverable.

3. Regulatory Assets and Liabilities

As a regulated entity OTP accounts for the financial effects of regulation in accordance with ASC 980, *Regulated Operations*. 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.

The following table indicates the amount of regulatory assets and liabilities recorded on OTP's balance sheet:

(in thousands)	December 31, 2009	December 31, 2008
Regulatory Assets:		
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pensions and Other Postretirement Benefits	$ 78,871	$ 64,490
Deferred Marked-to-Market Losses	7,614	1,162
Deferred Income Taxes	5,441	7,094
Minnesota Renewable Resource Rider Accrued Revenues	5,324	3,045
Accumulated ARO Accretion/Depreciation Adjustment	1,808	1,437
Minnesota General Rate Case Recoverable Expenses	1,693	1,457
MISO Schedule 16 and 17 Deferred Administrative Costs - ND	1,091	823
North Dakota Renewable Resource Rider Accrued Revenues	566	2,009
Minnesota Transmission Rider Accrued Revenues	420	--
South Dakota – Asset-Based Margin Sharing Shortfall	330	--
MISO Schedule 16 and 17 Deferred Administrative Costs - MN	252	526
Deferred Holding Company Formation Costs	248	--
Total Regulatory Assets	$ 103,658	$ 82,043

Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs – Net of Salvage	$ 12,043	$ 12,091
Deferred Income Taxes	4,965	4,943
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Gains on Other Postretirement Benefits	--	834
Deferred Marked-to-Market Gains	224	--
Other Regulatory Liabilities	148	139
Total Regulatory Liabilities	$ 17,380	$ 18,007
Net Regulatory Asset Position	$ 86,278	$ 64,036

The regulatory asset and regulatory liability related to the unrecognized transition obligation, prior service costs and actuarial losses and gains on pensions and other postretirement benefits represents benefit costs and actuarial losses and gains subject to recovery or return 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 and gains are required to be recognized as components of

Accumulated Other Comprehensive Income in equity under ASC 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, 2009 are related to forward purchases of energy scheduled for delivery through December 2013.

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*.

Minnesota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 and 2009 renewable resource costs incurred to serve Minnesota customers that have not been billed to Minnesota customers as of December 31, 2009. Minnesota Renewable Resource Rider Accrued Revenues are expected to be recovered over 51 months, from January 2010 through March 2014.

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

Minnesota General Rate Case Recoverable Expenses will be recovered over the next 25 months.

MISO Schedule 16 and 17 Deferred Administrative Costs – ND will be recovered over the next 35 months.

North Dakota Renewable Resource Rider Accrued Revenues relate to revenues earned on qualifying 2008 and 2009 renewable resource costs incurred to serve North Dakota customers that have not been billed to North Dakota customers as of December 31, 2009. North Dakota Renewable Resource Rider Accrued Revenues are expected to be recovered over 48 months, from January 2010 through December 2013.

Minnesota Transmission Rider Accrued Revenues are expected to be recovered over the next 12 months.

South Dakota – Asset-Based Margin Sharing Shortfall represents a difference in OTP’s South Dakota share of actual profit margins on wholesale sales of electricity from company-owned generating units and estimated profit margins from those sales that were used in determining current South Dakota retail electric rates. Net shortfalls or excess margins accumulated over 14 months will be subject to recovery or refund through future retail rate adjustments in South Dakota.

MISO Schedule 16 and 17 Deferred Administrative Costs – MN will be recovered over the next 11 months.

Deferred Holding Company Formation Costs will be amortized over the next 54 months.

The Accumulated Reserve for Estimated Removal Costs – Net of Salvage is reduced as actual removal costs are incurred.

Other Regulatory Liabilities includes: 1) a portion of profit margins on wholesales sales of purchased power subject to refund to South Dakota customers through future retail rate adjustments and 2) a deferred gain on the sale of utility property that will be paid to Minnesota retail electric customers over the next 24 years.

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 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, 2009 OTP had recognized, on a pretax basis, $1,030,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. 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. 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 2 of the fair value hierarchy set forth in ASC 820-10-35.

Electric revenues include $15,762,000 in 2009 and $27,236,000 in 2008 related to wholesale electric sales and net unrealized derivative gains on forward energy contracts and sales of financial transmission rights and daily settlements of virtual transactions in the MISO market, broken down as follows for the years ended December 31:

(in thousands)	2009	2008
Wholesale Sales - Company-Owned Generation	$ 12,579	$ 23,708
Revenue from Settled Contracts at Market Prices	110,124	520,280
Market Cost of Settled Contracts	(109,125)	(518,866)
Net Margins on Settled Contracts at Market	999	1,414
Marked-to-Market Gains on Settled Contracts	14,585	39,375
Marked-to-Market Losses on Settled Contracts	(13,431)	(37,138)
Net Marked-to-Market Gain on Settled Contracts	1,154	2,237
Unrealized Marked-to-Market Gains on Open Contracts	8,097	405
Unrealized Marked-to-Market Losses on Open Contracts	(7,067)	(528)
Net Unrealized Marked-to-Market Gain (Loss) on Open Contracts	1,030	(123)
Wholesale Electric Revenue	$ 15,762	$ 27,236

The following tables show the effect of marking to market forward contracts for the purchase and sale of energy on OTP's balance sheets:

(in thousands)	December 31, 2009	December 31, 2008
Current Asset – Marked-to-Market Gain	$ 8,321	$ 405
Regulatory Asset – Deferred Marked-to-Market Loss	7,614	1,162
Total Assets	15,935	1,567
Current Liability – Marked-to-Market Loss	(14,681)	(1,690)
Regulatory Liability – Deferred Marked-to-Market Gain	(224)	--
Total Liabilities	(14,905)	(1,690)
Net Fair Value of Marked-to-Market Energy Contracts	$ 1,030	$ (123)

(in thousands)	Year ended December 31, 2009	Year ended December 31, 2008
Fair Value at Beginning of Year	$ (123)	$ 632
Amount Realized on Contracts Entered into in Prior Year	123	(1,169)
Changes in Fair Value of Contracts Entered into in Prior Year	--	537
Net Fair Value of Contracts Entered into in Prior Year at Year End	--	--
Changes in Fair Value of Contracts Entered into in Current Year	1,030	(123)
Net Fair Value at End of Year	$ 1,030	$ (123)

The $1,030,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on December 31, 2009 is expected to be realized on settlement as scheduled over the following periods in the amounts listed:

(in thousands)	2010	2011	2012	Total
Net Gain	$ 389	$ 320	$ 321	$1,030

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. We have 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, 2009 was $222,000. As of December 31, 2009 OTP had a net credit risk exposure of $387,000 from four counterparties with investment grade credit ratings. OTP had no exposure at December 31, 2009 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 $387,000 credit risk exposure includes net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after December 31, 2009. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Mark-to-market losses of $72,000 on certain of OTP's derivative energy contracts included in the $14,681,000 derivative liability on December 31, 2009 are covered by deposited funds. Certain other of OTP's 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 immediate and ongoing full overnight collateralization on contracts in net liability positions. The aggregate fair value of all forward energy derivative contracts with credit-risk-related contingent features that are in a liability position on December 31, 2009 is $7,958,000, for which OTP has posted $7,760,000 as collateral in the form of offsetting gain positions on other contracts with one of its counterparties under a master netting agreement. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2009, OTP would have been required to post $198,000 in additional collateral to its counterparties. The remaining derivative liability balance of $6,651,000 relates to mark-to-market losses on contracts that have no ratings triggers or deposit requirements.

5. Common Shareholders' Equity and Cumulative Preferred Shares

At December 31, 2008 the Company had paid in capital of approximately $195,192,000, consisting entirely of equity infusions from Otter Tail Corporation, the parent company of OTP. As discussed in note 1, Otter Tail Corporation completed the holding company reorganization in July 2009. In conjunction with the reorganization, OTP issued 100 shares of common stock with a par value of $5, with the sole holder of those shares being Otter Tail Corporation. In addition to the issuance of the 100 shares of common stock, Otter Tail Corporation provided OTP with a capital infusion of approximately $9,668,000 of which $5,468,000 was for the transfer of the employee benefit liabilities and related tax benefits for the pension plan, executive survivor and supplemental retirement plan and other postretirement benefits from OTP to Otter Tail Corporation and $4,200,000 in additional equity in order align the debt to equity components for OTP.

At December 31, 2008, the Company had 1,500,000 shares of cumulative preferred shares authorized with no par value and 155,000 shares outstanding. The holder of the cumulative preferred shares was Otter Tail Corporation. As part of the holding company reorganization discussed in note 1, these shares were converted to term debt payable to Otter Tail Corporation.

6. Commitments and Contingencies

Construction Contracts, Capacity and Energy Requirements and Coal and Delivery Contracts
At December 31, 2009 OTP had commitments under contracts in connection with construction programs aggregating approximately $8,944,000. For capacity and energy requirements, OTP has agreements extending through 2034 at annual costs of approximately $19,374,000 in 2010, $16,599,000 in 2011, $17,844,000 in 2012 and $10,726,000 in 2013, $5,696,000 in 2014, and $84,579,000 for the years beyond 2014.

OTP has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. These contracts expire in 2010, 2011 and 2016. In total, OTP is committed to the minimum purchase of approximately $111,039,000 or to make payments in lieu thereof, under these contracts. The FCA mechanism lessens the risk of loss from market price changes because it provides for recovery of most fuel costs.

Operating Lease Commitments
The amounts of future operating lease payments are as follows:

(in thousands)	
2010	$ 2,491
2011	1,411
2012	924
2013	933
2014	944
Later years	15,642
Total	$ 22,345

Future operating lease payments are primarily related to coal rail-car leases. Rent expense was $2,893,000 in 2009 and $2,634,000 in 2008.

Sierra Club Complaint
On June 10, 2008 the Sierra Club filed a complaint in the U.S. District Court for the District of South Dakota (Northern Division) against OTP and two other co-owners of Big Stone Generating Station (Big Stone). The complaint alleged certain violations of the Prevention of Significant Deterioration and New Source Performance Standards (NSPS) provisions of the Clean Air Act (CAA) and certain violations of the South Dakota State Implementation Plan (South Dakota SIP). The action further alleged the defendants modified and operated Big Stone without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the CAA and the South Dakota SIP. The Sierra Club alleged the defendants' actions have contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club sought both declaratory and injunctive relief to bring the defendants into compliance with the CAA and the South Dakota SIP and to require the defendants to remedy the alleged

violations. The Sierra Club also seeks unspecified civil penalties, including a beneficial mitigation project. OTP believes these claims are without merit and that Big Stone was and is being operated in compliance with the CAA and the South Dakota SIP.

The defendants filed a motion to dismiss the Sierra Club complaint on August 12, 2008. On March 31, 2009 and April 6, 2009, the District Court issued a Memorandum and Order and Amended Memorandum and Order, respectively, granting the defendants' motion to dismiss the Sierra Club complaint. On April 17, 2009 the Sierra Club filed a motion for reconsideration of the Amended Memorandum Opinion and Order. The Sierra Club motion was opposed by the defendants. The Sierra Club motion for reconsideration was denied on July 22, 2009. On July 30, 2009 the Sierra Club filed a notice of appeal to the 8th U.S. Circuit Court of Appeals. The briefing schedule calls for the appellant to submit its brief by mid-October, for appellees to submit their brief by mid-November and for the appellant to submit its reply brief by the end of November. On October 13, 2009, the United States Department of Justice filed a motion seeking a 30-day extension of the time to file an amicus brief in support of the Sierra Club's position. The Court of Appeals granted this motion, as well as the appellees' subsequent joint motion with the Sierra Club, extending the time to file the appellees' brief and the Sierra Club's reply brief. Briefing was complete on January 22, 2010 on filing of the Sierra Club's reply brief. The ultimate outcome of this matter cannot be determined at this time.

Federal Power Act Complaint

On August 29, 2008 Renewable Energy System Americas, Inc. (RES), a developer of wind generation, and PEAK Wind Development, LLC (PEAK Wind), a group of landowners in Barnes County, North Dakota, filed a complaint with the FERC alleging that OTP and Minnkota Power Cooperative, Inc. (Minnkota) had acted together in violation of the Federal Power Act (FPA) to deny RES and PEAK Wind access to the Pillsbury Line, an interconnection facility which Minnkota owns to interconnect generation projects being developed by OTP and NextEra Energy Resources, Inc. (fka FPL Energy, Inc.) (NextEra). RES and PEAK Wind asked that (1) the FERC order Minnkota to interconnect its Glacier Ridge project to the Pillsbury Line, or in the alternative, (2) the FERC direct MISO to interconnect the Glacier Ridge project to the Pillsbury Line. RES and Peak Wind also requested that OTP, Minnkota and NextEra pay any costs associated with interconnecting the Glacier Ridge Project to the MISO transmission system which would result from the interconnection of the Pillsbury Line to the Minnkota transmission system, and that the FERC assess civil penalties against OTP. OTP answered the complaint on September 29, 2008, denying the allegations of RES and PEAK Wind and requesting that the FERC dismiss the complaint. On October 14, 2008, RES and PEAK Wind filed an answer to OTP's answer and, restated the allegations included in the initial complaint. RES and PEAK Wind also added a request that the FERC rescind both OTP's waiver from the FERC Standards of Conduct and its market-based rate authority. On October 28, 2008, OTP filed a reply, denying the allegations made by RES and PEAK Wind in its answer. By order issued on December 19, 2008, the FERC set the complaint for hearing and established settlement procedures. A formal settlement agreement was filed with the FERC requesting approval of the settlement and withdrawal of the complaint. OTP expects the FERC will issue an order approving the settlement and terminating the proceeding. The settlement is not expected to have a material impact on OTP's financial position or results of operations.

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, 2009 will not be material.

7. Short-Term and Long-Term Borrowings

Short-Term Debt

The following table presents the status of OTP's lines of credit as of December 31, 2009 and December 31, 2008:

(in thousands)	Line Limit	In Use on December 31, 2009	Restricted due to Outstanding Letters of Credit	Available on December 31, 2009	Available on December 31, 2008
OTP Credit Agreement[1]	$ 170,000	$ 1,585	$ 680	$ 167,735	$ 142,935

[1] On January 4, 2010, OTP paid off the remaining $58.0 million balance outstanding on its two-year, $75.0 million term loan that was originally due on May 20, 2011, using lower costs funds available under the OTP Credit Agreement. OTP did not incur any penalties for the early repayment and retirement of this debt.

The weighted average interest rates on short-term debt outstanding on December 31, 2009 and 2008 were 0.73% and 0.97%, respectively. The weighted average interest rate paid on short-term debt was 0.92% in 2009 and 3.09% in 2008.

Prior to Otter Tail Corporation's holding company reorganization on July 1, 2009, Otter Tail Corporation, dba Otter Tail Power Company (now OTP) was the borrower under a $170 million credit agreement (the OTP Credit Agreement) with an accordion feature whereby the line can be increased to $250 million as described in the OTP Credit Agreement. The credit agreement was entered into between Otter Tail Corporation, dba Otter Tail Power Company (now OTP) and JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association and Merrill Lynch Bank USA, as Banks, U.S. Bank National Association, as a Bank and as agent for the Banks, and Bank of America, N.A., as a Bank and as Syndication Agent. The OTP Credit Agreement is an unsecured revolving credit facility that OTP can draw on to support the working capital needs and other capital requirements of its operations. Borrowings under this line of credit bear interest at LIBOR plus 0.5%, subject to adjustment based on the ratings of the borrower's senior unsecured debt. The OTP Credit Agreement contains a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, incur indebtedness, 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. 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 the borrower's credit ratings. The OTP Credit Agreement is subject to renewal on July 30, 2011. Following Otter Tail Corporation's holding company reorganization, the OTP Credit Agreement is an obligation of OTP.

Long-Term Debt

On May 11, 2009 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. Proceeds from any equity issuances or borrowings by Otter Tail Corporation under the shelf registration could be used to fund OTP's capital additions or construction expenditures, retire OTP's debt or for other OTP capital requirements.

All long-term debt outstanding and listed on the Statements of Capitalization as of December 31, 2008 was owed by OTP to Otter Tail Corporation. As part of the holding company reorganization discussed in note 1, Otter Tail Power Company became the obligor of these debt series to the external debt holders.

Term Loan Agreement and Retirement

Prior to Otter Tail Corporation's holding company reorganization on July 1, 2009, Otter Tail Corporation, dba Otter Tail Power Company (now OTP) was the borrower under a $75 million term loan agreement (the OTP Loan Agreement). The OTP Loan Agreement was entered into between Otter Tail Corporation, dba Otter Tail Power Company (now OTP) and JPMorgan Chase Bank, N.A., as Administrative Agent, KeyBank National Association, as Syndication Agent, Union Bank, N.A., as Documentation Agent, and the Banks named therein. On completion of OTP's holding company formation on July 1, 2009, the OTP Loan Agreement became an obligation of OTP. The OTP Loan Agreement provided for a $75 million term loan due May 20, 2011. The proceeds were used to support OTP's construction of 49.5 MW of renewable wind-generation assets at the Luverne Wind Farm. In November 2009, OTP paid down $17 million of the $75 million term loan. OTP paid off the remaining $58 million balance in January 2010, using lower cost funds available under the OTP Credit Agreement. OTP did not incur any penalties for the early repayments and retirement of its debt under the Loan Agreement.

Borrowings under the OTP Loan Agreement bore interest at a rate equal to the base rate in effect from time to time. The base rate was a fluctuating rate per annum equal to (i) the highest of (A) JPMorgan Chase Bank, N.A.'s prime rate, (B) the Federal funds effective rate plus 0.5% per annum, and (C) a daily LIBOR rate plus 1.0% per annum, plus (ii) a margin of 1.5% to 3.0% determined on the basis of OTP's senior unsecured credit ratings, as provided in the Loan Agreement. The interest rate on borrowings under the OTP Loan Agreement was 3.73% at December 31, 2009.

The OTP Loan Agreement contained a number of restrictions on the business of OTP, including restrictions on its ability to merge, sell assets, make certain investments, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The OTP Loan Agreement also contained certain financial covenants. Specifically, OTP could not permit the ratio of its "Interest-bearing Debt" to "Total Capitalization" (each as defined in the OTP Loan Agreement) to be greater than 0.60 to 1.00, or permit its "Interest and Dividend Coverage Ratio" (as defined in the OTP Loan Agreement) for any period of four consecutive fiscal quarters to be less than 1.50 to 1.00. The OTP Loan Agreement also contained affirmative covenants and events of default. The OTP Loan Agreement did 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 obligations of OTP under the OTP Loan Agreement were unsecured.

Amendments to Note Purchase Agreements

In connection with Otter Tail Corporation's holding company reorganization on July 1, 2009, amendments to the following note purchase agreements were entered into in order to obtain the consent of the related noteholders to the reorganization.

Fourth Amendment to 2001 Note Purchase Agreement

On June 30, 2009 Otter Tail Corporation (now known as OTP) (Old Otter Tail) entered into a Fourth Amendment dated as of June 30, 2009 to Note Purchase Agreement dated as of December 1, 2001 (the Fourth Amendment) with the holders of the 2001 Notes referred to below, amending the Note Purchase Agreement dated as of December 1, 2001 among Old Otter Tail and each of the purchasers named on Schedule A attached thereto, as amended (the 2001 Note Purchase Agreement). The 2001 Note Purchase Agreement relates to the issuance and sale by Old Otter Tail, in a private placement transaction, of its $90,000,000 6.63% Senior Notes due December 1, 2011 (the 2001 Notes). The Fourth Amendment sets forth the terms and conditions of the 2001 Noteholders' consent to the holding company reorganization and amends certain provisions of the 2001 Note Purchase Agreement, both in connection with the holding company reorganization and for the purpose of achieving greater consistency among Old Otter Tail's note purchase agreements. These amendments include changes to negative covenants in the 2001 Note Purchase Agreement regarding limitations on liens and contingent liabilities, and to events of default. As provided in the Fourth Amendment, the 2001 Note Purchase Agreement and the 2001 Notes remained obligations of Old Otter Tail, under the name Otter Tail Power Company, following the effectiveness of the holding company reorganization. In addition, the guaranties issued by certain subsidiaries of Old Otter Tail under the 2001 Note Purchase Agreement and the 2001 Notes were released on the effectiveness of the holding company reorganization.

The 2001 Note Purchase Agreement, as amended, states 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 2001 Note Purchase Agreement, as amended, 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 agreement. The 2001 Note Purchase Agreement, as amended, contains a number of restrictions on the business of OTP. These include restrictions on the ability of OTP to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties.

Third Amendment to 2007 Note Purchase Agreement

On June 26, 2009 Old Otter Tail entered into a Third Amendment dated as of June 26, 2009 to Note Purchase Agreement dated as of August 20, 2007 (the Third Amendment) with the holders of the 2007 Notes referred to below, amending the Note Purchase Agreement dated as of August 20, 2007 among Old Otter Tail and each of the purchasers party thereto, as amended (the 2007 Note Purchase Agreement). The 2007 Note Purchase Agreement relates to the issuance and sale by Old Otter Tail of $155 million aggregate principal amount of Old Otter Tail's Senior Unsecured Notes in four series, in the designations and aggregate principal amounts set forth in the 2007 Note Purchase Agreement (the 2007 Notes). The Third Amendment sets forth the terms and conditions of the 2007 Noteholders' consent to the holding company reorganization and also amends certain provisions of the 2007 Note Purchase Agreement, both in connection with the holding company reorganization and for the purpose of achieving greater consistency among Old Otter Tail's note purchase agreements. These amendments include changes to negative covenants in the 2007 Note Purchase Agreement regarding limitations on liens and subsidiary guarantees. As provided in the Third Amendment, the 2007 Note Purchase Agreement and the 2007 Notes remained obligations of Old Otter Tail, under the name Otter Tail Power Company, following the effectiveness of the holding company reorganization.

The 2007 Note Purchase Agreement, as amended, states 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 2007 Note Purchase Agreement, as amended, states 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 2007 Note Purchase Agreement, as amended, contains a number of restrictions on the business of OTP. These include restrictions on the ability of OTP 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 aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2009 for each of the next five years are $58,000,000 for 2010, $90,000,000 for 2011, $10,400,000 for 2012 and no outstanding debt is scheduled to mature in 2013 and 2014.

Financial Covenants
As of December 31, 2009 OTP was in compliance with the financial statement covenants that existed in its debt agreements.

None of the Credit and Note Purchase Agreements 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.

Following Otter Tail Corporation's holding company reorganization on July 1, 2009: (1) the Cascade Note Purchase Agreement is an obligation of Otter Tail Corporation, as assignee of Otter Tail Corporation (now OTP) prior to the reorganization, and is guaranteed by Varistar and its material subsidiaries, and (2) the credit agreement relating to the $170 million revolving credit facility originally entered into by Otter Tail Corporation dba Otter Tail Power Company (now OTP), the 2001 Note Purchase Agreement and the 2007 Note Purchase Agreement are obligations of OTP.

Following Otter Tail Corporation's holding company reorganization on July 1, 2009 OTP's borrowing agreements are subject to certain financial covenants. Specifically:

- Under the OTP Credit Agreement, OTP may not permit the ratio of its Interest-bearing Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio to be less than 1.50 to 1.00, as provided in the Loan Agreement.

- Under the 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the financial guaranty insurance policy with Ambac Assurance Corporation relating to certain pollution control refunding bonds, OTP may not permit the ratio of its Consolidated Debt to Total Capitalization to be greater than 0.60 to 1.00 or permit its Interest and Dividend Coverage Ratio (or, in the case of the 2001 Note Purchase Agreement, its Interest Charges Coverage Ratio) to be less than 1.50 to 1.00, in each case as provided in the related borrowing or insurance agreement. In addition, under the 2001 Note Purchase Agreement and the 2007 Note Purchase Agreement, OTP may not permit its Priority Debt to exceed 20% of its Total Capitalization, as provided in the related agreement.

- In addition, under the Otter Tail Corporation 8.89% Senior Note, Otter Tail Corporation may not permit the ratio of OTP's Debt to OTP's total Capitalization to be greater than 0.60 to 1.00. The 8.89% Senior Note is not an obligation of OTP.

8. Pension Plan and Other Postretirement Benefits

Pension Plan
Otter Tail Corporation's noncontributory funded pension plan covers substantially all OTP employees hired prior to January 1, 2006. 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. Otter Tail Corporation reserves the right to discontinue the plan but no change or discontinuance may affect the pensions theretofore vested. OTP's portion of this plan makes up substantially all of the rights and obligations of the plan. The amounts presented herein are based upon the separate actuarial analysis of OTP and Otter Tail Corporation and its respective employees.

As of and for the twelve months ended December 31, 2008, OTP recorded the liabilities of the pension plan and is reflected in the amounts below. As part of the holding company restructuring completed in July 2009 discussed in note 1, the liabilities of the plan along with related tax benefits that related to Otter Tail Corporation were transferred to Otter Tail Corporation, resulting in a decrease of $3 million to OTP's equity.

The pension plan has a trustee who is responsible for pension payments to retirees. Six investment managers are responsible for managing the plan's assets. An independent actuary assists Otter Tail Corporation 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. None of the plan assets are invested in common stock, preferred stock or debt securities of OTP or Otter Tail Corporation.

Components of net periodic pension benefit cost:

(in thousands)	2009	2008
Service Cost--Benefit Earned During the Period	$ 3,859	$ 4,505
Interest Cost on Projected Benefit Obligation	11,028	11,019
Expected Return on Assets	(12,723)	(13,591)
Amortization of Prior-Service Cost	703	722
Amortization of Net Actuarial Loss	75	165
Net Periodic Pension Cost	$ 2,942	$ 2,820

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

	2009	2008
Discount Rate	6.70%	6.25%
Long-Term Rate of Return on Plan Assets	8.50%	8.50%
Rate of Increase in Future Compensation Level	3.75%	3.75%

The following table presents amounts recognized in the balance sheets as of December 31:

(in thousands)	2009	2008
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 2,597	$ 3,303
Unrecognized Actuarial Loss	69,378	56,652
Total Regulatory Assets	$ 71,975	$ 59,955
Noncurrent Liability:		
Otter Tail Power Company Portion	$ 64,733	$ 53,592
Corporate Portion Prior to Holding Company Formation	--	1,432
Total Noncurrent Liability	$ 64,733	$ 55,024
Deferred Income Taxes	--	$ 666
Accumulated Other Comprehensive Loss	--	$ 998

Funded status as of December 31:

(in thousands)	2009	2008
Accumulated Benefit Obligation:		
Otter Tail Power Company Portion	$(162,514)	$(149,896)
Corporate Portion Prior to Holding Company Formation	--	(3,780)
Total Accumulated Benefit Obligation	$(162,514)	$(153,676)
Projected Benefit Obligation:		
Otter Tail Power Company Portion	$(201,345)	$(177,556)
Corporate Portion Prior to Holding Company Formation	--	(5,003)
Fair Value of Plan Assets:	--	
Otter Tail Power Company Portion	136,612	123,964
Corporate Portion Prior to Holding Company Formation	--	3,571
Funded Status	$ (64,733)	$ (55,024)

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, 2009:

(in thousands)	2009	2008
Reconciliation of Fair Value of Otter Tail Power Company Portion of Plan Assets:		
Fair Value of Plan Assets at January 1	$ 123,964	$ 165,982
Actual Return on Plan Assets	17,546	(35,229)
Discretionary Company Contributions	3,888	2,000
Benefit Payments	(8,786)	(8,789)
Fair Value of Plan Assets at December 31	$ 136,612	$ 123,964
Estimated Asset Return	14.30%	(21.94)%
Reconciliation of Otter Tail Power Company Portion of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 177,556	$ 179,840
Service Cost	3,859	4,505
Interest Cost	11,028	11,109
Benefit Payments	(8,786)	(8,789)
Actuarial Loss (Gain)	17,688	(9,109)
Projected Benefit Obligation at December 31	$ 201,345	$ 177,556

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

	2009	2008
Discount Rate	6.00%	6.70%
Rate of Increase in Future Compensation Level	3.75%	3.75%

To develop the expected long-term rate of return on assets assumption, OTP considered the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of the pension portfolio.

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.

OTP bases 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.

The assumed rate of return on pension fund assets for the determination of 2010 net periodic pension cost is 8.50%.

Measurement Dates:	2009	2008
Net Periodic Pension Cost	January 1, 2009	January 1, 2008
End of Year Benefit Obligations	January 1, 2009 projected to December 31, 2009	January 1, 2008 projected to December 31, 2008
Market Value of Assets	December 31, 2009	December 31, 2008

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 in 2010 are:

(in thousands)	2010
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 664
Amortization of Unrecognized Actuarial Loss	1,963
Total Estimated Amortization	$ 2,627

<u>Cash flows</u>—OTP is not required to make a contribution to the pension plan in 2010.

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

(in thousands)	2010	2011	2012	2013	2014	Years 2015-2019
	$9,321	$9,675	$10,047	$10,485	$10,918	$66,673

OTP's pension plan asset allocations at December 31, 2009 and 2008, by asset category are as follows:

Asset Allocation	2009	2008
Large Capitalization Equity Securities	32.0%	39.6%
Small/Mid Capitalization Equity Securities	13.5%	9.2%
International Equity Securities	20.2%	8.3%
Total Equity Securities	65.7%	57.1%
Cash and Fixed-Income Securities	34.3%	42.9%
	100.0%	100.0%

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

- The Plan is managed to operate in perpetuity.
- The Plan will meet the pension benefit obligation payments of OTP.
- The Plan's assets should be invested with the objective of meeting current and future payment requirements while minimizing annual contributions and their volatility.
- The asset strategy reflects the desire to meet current and future benefit payments while considering a prudent level of risk and diversification.

The asset allocation strategy developed by OTP's Retirement Plans Administrative Committee is based on the current needs of the Plan, the investment objectives listed above, the investment preferences and risk tolerance of the committee and a desired degree of diversification.

The asset allocation strategy contains guideline percentages, at market value, of the total Plan invested in various asset classes. The strategic target allocation and the tactical range shown in the table that follows is a guide that will at times not be reflected in actual asset allocations that may be dictated by prevailing market conditions, independent actions of the Retirement Plans Administrative Committee (RPAC) and/or investment managers, and required cash flows to and from the Plan. The tactical range provides flexibility for the investment managers' portfolios to vary around the target allocation without the need for immediate rebalancing.

Allocation targets and tactical ranges shown below reflect the revised Investment Policy Statement recently approved by the RPAC. Each of the asset categories is within its respective tactical range. The RPAC monitors actual asset allocations and directs contributions and withdrawals toward maintaining the current targeted allocation percentages listed below.

Asset Allocation	Strategic Target	Tactical Range
Large Capitalization Equity Securities	30%	20%-40%
Small/Mid Capitalization Equity Securities	12%	6%-22%
International Equity Securities	18%	10%-30%
Total Equity Securities	60%	45%-75%
Cash and Fixed-Income Securities	40%	20%-50%

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.

As of and for the twelve months ended December 31, 2008, OTP recorded the liabilities of this plan and is reflected in the amounts below. As part of the holding company restructuring completed in July 2009 discussed in note 1, the liabilities of the plan along with related tax benefits that related to Otter Tail Corporation were transferred to Otter Tail Corporation, resulting in an increase of $7.6 million to OTP's equity.

Components of net periodic pension benefit cost:

(in thousands)	2009	2008
Service Cost--Benefit Earned During the Period	$ 438	$ 417
Interest Cost on Projected Benefit Obligation	986	926
Amortization of Prior-Service Cost	41	40
Amortization of Net Actuarial Loss	224	289
Net Periodic Pension Cost	$ 1,689	$ 1,672

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

	2009	2008
Discount Rate	6.70%	6.25%
Rate of Increase in Future Compensation Level	4.70%	4.70%

The following table presents amounts recognized in the balance sheets as of December 31:

(in thousands)	2009	2008
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 389	$ 421
Unrecognized Actuarial Loss	4,433	4,114
Total Regulatory Assets	$ 4,822	$ 4,535
Projected Benefit Obligation Liability – Net Amount Recognized:		
Otter Tail Power Company Portion	$ (16,541)	$ (15,612)
Corporate Portion Prior to Holding Company Formation	--	(10,276)
Total Projected Benefit Obligation Liability – Net Amount Recognized	$ (16,541)	$ (25,888)
Deferred Income Taxes		$ 1,194
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	--	$ 166
Unrecognized Actuarial Loss	--	1,626
Total Accumulated Other Comprehensive Loss	--	$ 1,792

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, 2009 and a statement of the funded status as of December 31 of both years:

(in thousands)	2009	2008
Reconciliation of Fair Value of Otter Tail Power Company Portion of Plan Assets:		
Fair Value of Plan Assets at January 1	$ --	$ --
Actual Return on Plan Assets	--	--
Employer Contributions	1,112	1,067
Benefit Payments	(1,112)	(1,067)
Fair Value of Plan Assets at December 31	$ --	$ --
Reconciliation of Otter Tail Power Company Portion of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 15,612	$ 15,611
Service Cost	438	417
Interest Cost	986	926
Benefit Payments	(1,112)	(1,067)
Plan Amendments	24	38
Actuarial Loss (Gain)	593	(313)
Projected Benefit Obligation at December 31	$ 16,541	$ 15,612

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

	2009	2008
Discount Rate	6.00%	6.70%
Rate of Increase in Future Compensation Level	4.71%	4.70%

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 2010 are:

(in thousands)	2010
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 43
Amortization of Unrecognized Actuarial Loss	278
Total Estimated Amortization	$ 321

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:

(in thousands)	2010	2011	2012	2013	2014	Years 2015-2019
	$1,114	$1,224	$1,279	$1,268	$1,274	$7,729

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 SFAS 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.

As of and for the twelve months ended December 31, 2008, OTP recorded the liabilities of this plan and is reflected in the amounts below. As part of the holding company restructuring completed in July 2009 discussed in note 1, the liabilities of the plan along with related tax benefits that related to Otter Tail Corporation were transferred to Otter Tail Corporation, resulting in an increase of $1.0 million to OTP's equity.

Components of net periodic postretirement benefit cost:

(in thousands)	2009	2008
Service Cost--Benefit Earned During the Period	$ 1,111	$ 1,073
Interest Cost on Projected Benefit Obligation	2,782	2,616
Amortization of Transition Obligation	727	727
Amortization of Prior-Service Cost	205	205
Amortization of Net Actuarial Loss	--	(35)
Expense Decrease Due to Medicare Part D Subsidy	(1,335)	(1,172)
Net Periodic Postretirement Benefit Cost	$ 3,490	$ 3,414

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

	2009	2008
Discount Rate	6.70%	6.25%

The following table presents amounts recognized in the balance sheets as of December 31:

(in thousands)	2009	2008
Regulatory Asset:		
Unrecognized Transition Obligation	$ 1,093	$ 1,454
Unrecognized Prior Service Cost	1,361	1,567
Unrecognized Net Actuarial Gain	(379)	(3,855)
Net Regulatory Asset (Liability)	$ 2,075	$ (834)
Projected Benefit Obligation Liability – Net Amount Recognized:		
Otter Tail Power Company Portion	$(36,656)	$(31,749)
Corporate Portion Prior to Holding Company Formation	--	(872)
Total Projected Benefit Obligation Liability – Net Amount Recognized	$(36,656)	$(32,621)
Accumulated Other Comprehensive Loss:		
Unrecognized Transition Obligation	$ 653	$ 871
Corporate Items Prior to Holding Company Formation:		
Unrecognized Transition Obligation	--	52
Unrecognized Prior Service Cost	--	26
Unrecognized Net Actuarial Gain	--	(64)
Total Accumulated Other Comprehensive Loss	$ 653	$ 885
Deferred Income Taxes:		
Otter Tail Power Company Portion	$ 436	$ 582
Corporate Portion Prior to Holding Company Formation	--	8
Total Deferred Income Taxes	$ 436	$ 590

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations and accrued postretirement benefit cost over the two-year period ended December 31, 2009:

(in thousands)	2009	2008
Reconciliation of Fair Value of Otter Tail Power Company Portion of Plan Assets:		
Fair Value of Plan Assets at January 1	$ --	$ --
Actual Return on Plan Assets	--	--
Company Contributions	1,254	1,577
Benefit Payments (Net of Medicare Part D Subsidy)	(3,113)	(3,392)
Participant Premium Payments	1,859	1,815
Fair Value of Plan Assets at December 31	$ --	$ --
Reconciliation of Otter Tail Power Company Portion of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 31,749	$ 29,832
Service Cost (Net of Medicare Part D Subsidy)	909	872
Interest Cost (Net of Medicare Part D Subsidy)	1,921	1,801
Benefit Payments (Net of Medicare Part D Subsidy)	(3,113)	(3,392)
Participant Premium Payments	1,859	1,815
Actuarial Loss	3,331	821
Projected Benefit Obligation at December 31	$ 36,656	$ 31,749

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

	2009	2008
Discount Rate	5.75%	6.70%

Assumed healthcare cost-trend rates as of December 31:

	2009	2008
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	7.10%	7.40%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	7.63%	8.00%
Rate at Which the Cost-Trend Rate is Assumed to Decline	5.00%	5.00%
Year the Rate Reaches the Ultimate Trend Rate	2025	2017

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 2009 would have the following effects:

(in thousands)	1 point increase	1 point decrease
Effect on the Postretirement Benefit Obligation	$ 3,727	$(3,188)
Effect on Total of Service and Interest Cost	$ 365	$ (302)
Effect on Expense	$ 579	$ (556)

Measurement dates:	2009	2008
Net Periodic Postretirement Benefit Cost	January 1, 2009	January 1, 2008
End of Year Benefit Obligations	January 1, 2009 projected to December 31, 2009	January 1, 2008 projected to December 31, 2008

The estimated net amounts of unrecognized transition obligation and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic postretirement benefit cost in 2010 are:

(in thousands)	2010
Decrease in Regulatory Assets:	
Amortization of Transition Obligation	$ 364
Amortization of Unrecognized Prior Service Cost	204
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Transition Obligation	363
Total Estimated Amortization	$ 931

Cash flows--OTP expects to contribute $2.3 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2010. OTP expects to receive a Medicare Part D subsidy from the Federal government of approximately $504,000 in 2010. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(in thousands)	2010	2011	2012	2013	2014	Years 2015-2019
	$2,321	$2,456	$2,554	$2,671	$2,856	$16,127

Leveraged Employee Stock Ownership Plan

OTP has a leveraged employee stock ownership plan for the benefit of all its electric utility employees. Contributions made by OTP were $761,000 for 2009, $738,000 for 2008 and $733,000 for 2007.

9. 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:

Long-Term Debt--The fair value of OTP's long-term debt is estimated based on the current rates available to OTP for the issuance of debt. OTP’s long-term debt subject to variable interest rates of $68.4 million and OTP’s notes payable to parent company, Otter Tail Corporation, approximate fair value.

	December 31, 2009		December 31, 2008	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$(354,425)	$(314,567)	$(256,790)	$(229,404)

10. Property, Plant and Equipment

(in thousands)	December 31, 2009	December 31, 2008
Electric Plant		
Production	$ 660,654	$ 590,252
Transmission	216,508	201,456
Distribution	357,623	337,296
General	78,230	76,643
Electric Plant	1,313,015	1,205,647
Less Accumulated Depreciation and Amortization	492,902	467,855
Electric Plant Net of Accumulated Depreciation	820,113	737,792
Construction Work in Progress	11,104	25,547
Net Electric Plant	831,217	763,339
Other Property		
Land	776	902
Net Plant	$ 831,993	$ 764,241

The estimated service lives for rate-regulated properties is 5 to 65 years.

	Service Life Range	
(years)	Low	High
Electric Fixed Assets:		
Production Plant	34	62
Transmission Plant	40	55
Distribution Plant	15	55
General Plant	5	65

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 12/31/2009	2009/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

11. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2009 and 2008) to net income before total income tax expense for the following reasons:

(in thousands)	2009	2008
Tax Computed at Federal Statutory Rate	$ 12,154	$ 16,156
Increases (Decreases) in Tax from:		
State Income Taxes Net of Federal Income Tax Benefit	1,584	1,967
Differences Reversing in Excess of Federal Rates	893	1,089
Federal Production Tax Credit	(6,533)	(3,234)
Tax Depreciation - Treasury Grant for Wind Farms	(3,169)	--
Allowance for Funds Used During Construction - Equity	(1,113)	(975)
Investment Tax Credit Amortization	(992)	(1,125)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(870)	(369)
Dividend Received/Paid Deduction	(683)	(718)
Permanent and Other Differences	(625)	135
Total Income Tax Expense	$ 646	$ 12,926
Overall Effective Federal and State Income Tax Rate	1.9%	28.0%
Income Tax Expense Includes the Following:		
Current Federal Income Taxes	$ (35,666)	$ (18,475)
Current State Income Taxes	2,723	(1,581)
Deferred Federal Income Taxes	42,500	32,212
Deferred State Income Taxes	(516)	5,498
Federal Production Tax Credit	(6,533)	(3,234)
Investment Tax Credit Amortization	(992)	(1,125)
North Dakota Wind Tax Credit Amortization – Net of Federal Taxes	(870)	(369)
Total	$ 646	$ 12,926

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

(in thousands)	2009	2008
Deferred Tax Assets		
Related to North Dakota Wind Tax Credits	$ 58,191	$ 35,902
Benefit Liabilities	22,041	22,438
Differences Related to Property	10,738	9,581
Net Operating Loss Carryforward	7,529	1,643
Federal Production Tax Credits	6,533	--
Amortization of Tax Credits	4,966	4,946
Vacation Accrual	1,312	1,320
Other	1,605	2,093
Total Deferred Tax Assets	$ 112,915	$ 77,923
Deferred Tax Liabilities		
Differences Related to Property	$(203,597)	$(149,981)
Related to North Dakota Wind Tax Credits	(15,132)	(9,090)
Transfer to Regulatory Asset	(5,808)	(7,045)
Excess Tax over Book Pension	(2,898)	(2,530)
Renewable Resource Rider Accrued Revenue	(2,300)	(1,971)
Impact of State Net Operating Losses on Federal Taxes	(2,060)	--
Other	(4,458)	424
Total Deferred Tax Liabilities	$(236,253)	$(170,193)
Deferred Income Taxes	$(123,338)	$ (92,270)

The amounts of unused North Dakota wind energy tax credits being carried forward for North Dakota tax purposes as of December 31, 2009 are: $10.2 million which will fully expire in 2017, $17.7 million which will fully expire in 2032, and $15.4 million which will fully expire in 2033. The tax effect of net operating losses being carried forward for North Dakota tax purposes as of December 31, 2009 was $4.0 million, of which $1.4 million expire in 2029 and $2.6 million expire in 2030. The tax effect of net operating losses being carried forward for Minnesota tax purposes as of December 31, 2009 was $2.1 million which expire in 2024.

The following table summarizes the activity related to our unrecognized tax benefits:

(in thousands)	Total
Balance at January 1, 2009	$ 65
Increases Related to Tax Positions	--
Uncertain Positions Resolved in 2009	(65)
Balance at December 31, 2009	$ --

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, 2009 Otter Tail Corporation is no longer subject to U.S. federal income tax examinations by tax authorities for years before 2006. As of December 31, 2009 Otter Tail Corporation's earliest open tax year in which an audit can be initiated by state taxing authorities in Otter Tail Corporation's major operating jurisdictions is 2005 for Minnesota and 2006 for North Dakota. OTP classifies interest and penalties on tax uncertainties as components of the provision for income taxes.

12. Asset Retirement Obligations (AROs)

OTP's AROs are related to coal-fired generation plants and its 92 wind turbines located in North Dakota. The AROs include site restoration, closure of ash pits, and removal of storage tanks, structures, generators and asbestos. 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.

During 2009, OTP recorded new obligations related to the removal of 33 wind turbines and restoration of its tower sites located at the Luverne Wind Farm in Steele County, North Dakota, and for future renovations of areas currently occupied by various water treatment sludge ponds at the Big Stone Plant site. OTP determined the fair value of its future obligations related to the removal of its 33 wind turbines located at the Luverne Wind Farm by engaging an outside engineering firm with expertise in demolition and removal to provide an estimate of the current costs to remove these assets, then projected the costs forward to 2034 using an inflation rate of 2.9% per year and discounted this amount back to its present value using a credit adjusted risk free rate of 8.3%. OTP determined the fair value of its future obligations for future renovations of areas currently occupied by various water treatment sludge ponds by conducting an internal assessment incorporating the services of a local contractor to estimate the current cost to renovate these areas. OTP then projected the costs forward to 2024 using an inflation rate of 2.7% per year and discounted this amount back to its present value using a credit adjusted risk free rate of 8.75%.

During 2008, OTP recorded new obligations related to the removal of 32 wind turbines and restoration of its tower sites located at the Ashtabula Wind Energy Center in Barnes County, North Dakota and made revisions to previously recorded obligations related to site restoration, closure of ash pits, and removal of storage tanks, structures, generators and asbestos at its coal-fired generation plants. OTP determined the fair value of its future obligations related to the removal of 32 wind turbines located at the Ashtabula Wind Energy Center by engaging an outside engineering firm with expertise in demolition and removal to provide an estimate of the current costs to remove these assets, then projected the costs forward to 2033 using an inflation rate of 3.1% per year and discounted this amount back to its present value using a credit adjusted risk free rate of 9.0%.

Reconciliations of carrying amounts of the present value of OTP's legal AROs, capitalized asset retirement costs and related accumulated depreciation and a summary of settlement activity for the years ended December 31, 2009 and 2008 are presented in the following table:

(in thousands)	2009	2008
Asset Retirement Obligations		
Beginning Balance	$ 3,298	$ 2,447
New Obligations Recognized	436	317
Adjustments Due to Revisions in Cash Flow Estimates	--	407
Accrued Accretion	316	127
Settlements	--	--
Ending Balance	$ 4,050	$ 3,298
Asset Retirement Costs Capitalized		
Beginning Balance	$ 1,061	$ 1,309
New Obligations Recognized	436	317
Adjustments Due to Revisions in Cash Flow Estimates	--	(565)
Settlements	--	--
Ending Balance	$ 1,497	$ 1,061
Accumulated Depreciation - Asset Retirement Costs Capitalized		
Beginning Balance	$ 179	$ 185
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	(34)
Accrued Depreciation	54	28
Settlements	--	--
Ending Balance	$ 233	$ 179
Settlements		
Original Capitalized Asset Retirement Cost - Retired	$ --	$ --
Accumulated Depreciation	--	--
Asset Retirement Obligation	$ --	$ --
Settlement Cost	--	--
Gain on Settlement – Deferred Under Regulatory Accounting	$ --	$ --

13. Quantitative and Qualitative Disclosures about Market Risk

At December 31, 2009 OTP had exposure to market risk associated with interest rates because we had $1.6 million in short-term debt outstanding subject to variable interest rates that are indexed to LIBOR plus 0.5% under the credit agreement relating to OTP's $170 million revolving credit facility.

The majority of our consolidated long-term debt has fixed interest rates. The interest rate on variable rate long-term debt is reset on a periodic basis reflecting current market conditions. We manage our 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, 2009 we had $68.4 million of long-term debt subject to variable interest rates. However, $58.0 million of this debt was OTP's variable rate term loan due May 20, 2011 that was early retired on January 4, 2010, without penalty. Assuming no change in our financial structure, if variable interest rates were to average one percentage point higher or lower than the average variable rate on December 31, 2009, annualized interest expense and pre-tax earnings would change by approximately $104,000.

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

OTP has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of December 31, 2009 OTP had recognized, on a pretax basis, $1,030,000 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. 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 sales contracts that are marked to market as of December 31, 2009, are 100% offset by forward energy purchase contracts in terms of volumes, delivery periods and delivery points.

We have 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. With the advent of the MISO Day 2 market in April 2005, we made several changes to our energy risk management policy to recognize new trading opportunities created by this new market. Most of the changes were in new volumetric limits and loss limits to adequately manage the risks associated with these new opportunities. In addition, we implemented a Value at Risk (VaR) limit to further manage market price risk. There was no market exposure risk as of December 31, 2009 due to all forward positions being closed.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity and electricity generating capacity on our consolidated balance sheet as of December 31, 2009 and the change in our consolidated balance sheet position from December 31, 2008 to December 31, 2009:

(in thousands)	December 31, 2009
Current Asset – Marked-to-Market Gain	$ 8,321
Regulatory Asset – Deferred Marked-to-Market Loss	7,614
Total Assets	15,935
Current Liability – Marked-to-Market Loss	(14,681)
Regulatory Liability – Deferred Marked-to-Market Gain	(224)
Total Liabilities	(14,905)
Net Fair Value of Marked-to-Market Energy Contracts	$ 1,030

(in thousands)	Year ended December 31, 2009
Fair Value at Beginning of Year	$ (123)
Amount Realized on Contracts Entered into in 2008 and Settled in 2009	123
Changes in Fair Value of Contracts Entered into in 2008	--
Net Fair Value of Contracts Entered into in 2009 at Year End 2009	--
Changes in Fair Value of Contracts Entered into in 2009	1,030
Net Fair Value at End of Year	$ 1,030

The $1,030,000 in recognized but unrealized net gains on the forward energy and capacity purchases and sales marked to market on December 31, 2009 is expected to be realized on settlement as scheduled over the following years in the amounts listed:

(in thousands)	2010	2011	2012	Total
Net Gain	$ 389	$ 320	$ 321	$1,030

OTP has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy and capacity purchases and sales agreements. We have 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, 2009 was $222,000. As of December 31, 2009 OTP had a net credit risk exposure of $387,000 from four counterparties with investment grade credit ratings. OTP had no exposure at December 31, 2009 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 $387,000 credit risk exposure includes net amounts due to OTP on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of electricity scheduled for delivery after December 31, 2009. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	21,700			1,159,002
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value	(39,478)			(4,140,906)
4	Total (lines 2 and 3)	(39,478)			(4,140,906)
5	Balance of Account 219 at End of Preceding Quarter/Year	(17,778)			(2,981,904)
6	Balance of Account 219 at Beginning of Current Year				(3,674,541)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				3,021,382
9	Total (lines 7 and 8)				3,021,382
10	Balance of Account 219 at End of Current Quarter/Year				(653,159)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/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			1,180,702		
2					
3			(4,180,384)		
4			(4,180,384)	35,124,611	30,944,227
5			(2,999,682)		
6			(3,674,541)		
7					
8			3,021,382		
9			3,021,382	34,078,812	37,100,194
10			(653,159)		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

Schedule Page: 122(a)(b) Line No.: 1 Column: b

On July 1, 2009 Otter Tail Power Company, 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 (formerly known as Otter Tail Holding Company). This footnote shows how pages 122a-122b would have been prepared if Otter Tail Power Company had been a wholly owned subsidiary in 2008.

Otter Tail Power Company **End of 2009/Q4**

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

Line No.	Item	Unrealized gains and losses on available-for-sale securities	Minimum pension liability adjustment (net amount)	Foreign currency hedges	Other Adjustments
1	Balance of account 219 at beginning of preceding year				(2,317,621)
2	Preceding quarter/year to date reclassifications from account 219 to net income				
3	Preceding quarter/year to date changes in fair value				(1,356,920)
4	Total (lines 2 and 3)				(1,356,920)
5	Balance of account 219 at end of preceding quarter/year				(3,674,541)
6	Balance of account 219 at beginning of current year				(3,674,541)
7	Current quarter/year to date reclassifications from account 219 to net income				
8	Current quarter/year to date changes in fair value				3,021,382
9	Total (lines 7 and 8)				3,021,382
10	Balance of account 219 at end of current quarter/year				(653,159)

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Otter Tail Power Company **End of 2009/Q4**

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

Line No.	Other cash flow Hedges Interest rate swaps	Other cash flow hedges (specify)	Totals for each category of items recorded in account 219	Net income (carried (forward from page 117, line 78)	Total Comprehensive Income
1			(2,317,621)		
2			0		
3			(1,356,920)		
4			(1,356,920)	33,233,958	31,877,038
5			(3,674,541)		
6			(3,674,541)		
7			0		
8			3,021,382		
9			3,021,382	34,078,812	37,100,194
10			(653,159)		

Page 122b Footnote

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	1,208,265,884	1,208,265,884
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	103,072,392	103,072,392
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,311,338,276	1,311,338,276
9	Leased to Others		
10	Held for Future Use	29,656	29,656
11	Construction Work in Progress	11,103,572	11,103,572
12	Acquisition Adjustments	1,647,129	1,647,129
13	Total Utility Plant (8 thru 12)	1,324,118,633	1,324,118,633
14	Accum Prov for Depr, Amort, & Depl	492,901,483	492,901,483
15	Net Utility Plant (13 less 14)	831,217,150	831,217,150
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	489,671,107	489,671,107
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	1,872,975	1,872,975
22	Total In Service (18 thru 21)	491,544,082	491,544,082
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	1,357,401	1,357,401
33	Total Accum Prov (equals 14) (22,26,30,31,32)	492,901,483	492,901,483

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
					5
					6
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					32
					33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	1,301,974	
4	(303) Miscellaneous Intangible Plant	2,619,503	490,382
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	3,921,477	490,382
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,439,647	131,438
9	(311) Structures and Improvements	59,834,341	475,730
10	(312) Boiler Plant Equipment	191,737,051	6,910,229
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	56,901,022	3,485,172
13	(315) Accessory Electric Equipment	19,089,954	646,153
14	(316) Misc. Power Plant Equipment	5,256,089	274,597
15	(317) Asset Retirement Costs for Steam Production	249,359	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	334,507,463	11,923,319
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	241,333	-26,859
29	(332) Reservoirs, Dams, and Waterways	1,613,169	127,099
30	(333) Water Wheels, Turbines, and Generators	976,498	85,622
31	(334) Accessory Electric Equipment	478,134	
32	(335) Misc. Power PLant Equipment	147,892	
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)	3,764,649	185,862
36	D. Other Production Plant		
37	(340) Land and Land Rights	126,762	
38	(341) Structures and Improvements	4,643,477	5,728,860
39	(342) Fuel Holders, Products, and Accessories	1,547,234	
40	(343) Prime Movers	31,462,189	-2,608
41	(344) Generators	193,123,849	55,690,791
42	(345) Accessory Electric Equipment	1,594,131	13,086,443
43	(346) Misc. Power Plant Equipment	418,487	3,499
44	(347) Asset Retirement Costs for Other Production	812,128	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	233,728,257	74,506,985
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	572,000,369	86,616,166

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	362,682	
49	(352) Structures and Improvements		
50	(353) Station Equipment	62,569,455	7,233,529
51	(354) Towers and Fixtures	4,692,263	
52	(355) Poles and Fixtures	76,420,961	2,393,716
53	(356) Overhead Conductors and Devices	66,885,953	1,704,766
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices	80,637	-7,964
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)	211,011,951	11,324,047
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	960,533	882
61	(361) Structures and Improvements		
62	(362) Station Equipment	50,069,965	3,928,843
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	56,188,170	1,578,873
65	(365) Overhead Conductors and Devices	43,138,261	141,399
66	(366) Underground Conduit		
67	(367) Underground Conductors and Devices	54,263,039	2,261,047
68	(368) Line Transformers	59,178,214	3,936,417
69	(369) Services	40,185,029	2,288,345
70	(370) Meters	29,570,322	1,383,352
71	(371) Installations on Customer Premises	3,775,523	177,226
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,341,585	167,679
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	341,670,641	15,864,063
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	1,434,176	12,852
87	(390) Structures and Improvements	29,292,294	518,156
88	(391) Office Furniture and Equipment	7,898,556	718,021
89	(392) Transportation Equipment	26,087,253	1,631,034
90	(393) Stores Equipment		
91	(394) Tools, Shop and Garage Equipment	4,052,530	162,515
92	(395) Laboratory Equipment	249,167	
93	(396) Power Operated Equipment	553,466	516,945
94	(397) Communication Equipment	5,798,061	
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	75,365,503	3,559,523
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)	75,365,503	3,559,523
100	TOTAL (Accounts 101 and 106)	1,203,969,941	117,854,181
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)	1,203,969,941	117,854,181

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

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			1,301,974		3
391,460			2,718,425		4
391,460			4,020,399		5
					6
					7
			1,571,085		8
28,805			60,281,266		9
2,123,241			196,524,039		10
					11
1,473,813			58,912,381		12
507,485		2,774,055	22,002,677		13
82,256			5,448,430		14
	65,386		314,745		15
4,215,600	65,386	2,774,055	345,054,623		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			307,623		27
8,530			205,944		28
3,192			1,737,076		29
5,960			1,056,160		30
		110,362	588,496		31
			147,892		32
					33
					34
17,682		110,362	4,043,191		35
					36
			126,762		37
			10,372,337		38
			1,547,234		39
26,746			31,432,835		40
			248,814,640		41
		87,633	14,768,207		42
			421,986		43
	369,894		1,182,022		44
26,746	369,894	87,633	308,666,023		45
4,260,028	435,280	2,972,050	657,763,837		46

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
		-366	362,316		48
					49
24,472		-5,664,751	64,113,761		50
			4,692,263		51
120,449			78,694,228		52
85,074			68,505,645		53
					54
			72,673		55
					56
					57
229,995		-5,665,117	216,440,886		58
					59
		366	961,781		60
					61
821,647		2,688,750	55,865,911		62
					63
66,357			57,700,686		64
132,733			43,146,927		65
					66
128,769			56,395,317		67
458,656		3,951	62,659,926		68
34,887			42,438,487		69
767,789			30,185,885		70
121,805			3,830,944		71
					72
93,767			4,415,497		73
					74
2,626,410		2,693,067	357,601,361		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			1,447,028		86
76,663			29,733,787		87
1,387,544		-32,601	7,196,432		88
1,513,985			26,204,302		89
					90
215,293			3,999,752		91
126,051			123,116		92
18,937			1,051,474		93
74,760		32,601	5,755,902		94
					95
3,413,233			75,511,793		96
					97
					98
3,413,233			75,511,793		99
10,921,126	435,280		1,311,338,276		100
					101
					102
					103
10,921,126	435,280		1,311,338,276		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1	Not applicable				
2					
3					
4					
5					
6					
7					
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46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	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				
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33				
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46				
47	Total			29,656

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Bottineau, ND - Build new substation	165,537
2	Bemidji, MN - Grand Rapids, MN - Construct transmission line	1,490,299
3	Fargo, ND - St. Cloud, MN - Construct transmission line	1,512,775
4	Brookings, SD - SE Twin Cities - Construct transmission line	861,274
5	System Wide - cyber security implementation	627,850
6	Buffalo, ND - Transmission line	100,275
7	Eckleson, ND - Build platform substation	106,563
8	Bottineau, ND - 12.5 kv conversion project	113,048
9	System WIde - Reinforce rejected poles	122,726
10	Fergus Falls, MN - Hoot Lake Plant - Install coal conveying equipment	122,755
11	Fergus Falls, MN - Build new substation	123,181
12	Morris, MN - Replace substation	124,311
13	Big Stone City, SD - Big Stone Plant - 2009 Miscellaneous	143,018
14	Fergus Falls, MN - Construct double circuit line from new substation	158,268
15	Sisseton, SD - System upgrades	170,495
16	Fergus Falls, MN - Purchase aerial basket truck	172,209
17	Big Stone CIty, SD - Big Stone Plant - Replace control system	180,256
18	Ashtabula, ND - Construct wind farm	250,000
19	Fergus Falls, MN - Purchase aerial basket truck	264,469
20	Fergus Falls, MN - Peaking plant development	438,681
21	Big Stone City, SD - Transmission line uprate/construction	506,081
22	Miscellaneous projects under $100,000	3,349,501
23		
24		
25		
26		
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43	TOTAL	11,103,572

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	464,836,693	464,836,693		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	34,951,884	34,951,884		
4	(403.1) Depreciation Expense for Asset Retirement Costs	45,895	45,895		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,351,746	1,351,746		
7	Other Clearing Accounts	92,611	92,611		
8	Other Accounts (Specify, details in footnote):	47,670	47,670		
9	Other	8,580	8,580		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	36,498,386	36,498,386		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	10,529,666	10,529,666		
13	Cost of Removal	2,840,429	2,840,429		
14	Salvage (Credit)	1,403,272	1,403,272		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	11,966,823	11,966,823		
16	Other Debit or Cr. Items (Describe, details in footnote):	302,851	302,851		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	489,671,107	489,671,107		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	197,027,760	197,027,760		
21	Nuclear Production				
22	Hydraulic Production-Conventional	1,961,763	1,961,763		
23	Hydraulic Production-Pumped Storage				
24	Other Production	26,152,172	26,152,172		
25	Transmission	83,375,396	83,375,396		
26	Distribution	149,930,597	149,930,597		
27	Regional Transmission and Market Operation				
28	General	31,223,419	31,223,419		
29	TOTAL (Enter Total of lines 20 thru 28)	489,671,107	489,671,107		

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

Inventory costs cleared to construction or utility operating expense.

Schedule Page: 219 Line No.: 8 Column: c

Transferred to a regulatory liability for the portion of depreciation accrued for future removal cost on assets that are subject to asset retirement obligation (ARO) accounting.

Schedule Page: 219 Line No.: 9 Column: c

Adjusted ARO Accumulated provision for Depreciation due to new estimates.

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Not applicable			
2				
3				
4				
5				
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7				
8				
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28				
29				
30				
31				
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39				
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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 form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
				4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	7,613,394	8,314,739	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)	4,373,508	5,072,842	Production
8	Transmission Plant (Estimated)	3,974,667	3,748,798	Various
9	Distribution Plant (Estimated)	6,767,676	6,664,530	Various
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	285,702	286,839	Fleet Service
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	15,401,553	15,773,009	
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)	23,014,947	24,087,748	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

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

Consists of parts inventory at the Fleet Service Department.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2010 No. (d)	2010 Amt. (e)
1	Balance-Beginning of Year	34,613.00		14,054.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Other Purchases-see notes				
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	12,278.00			
19	Other:				
20	EPA Adjust -				
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	22,335.00		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	203.41		202.97	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	203.41			
40	Balance-End of Year			202.97	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	203.41	14,187		
45	Gains	203.41	14,187		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2011		2012		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
14,054.00		14,054.00		365,404.00		442,179.00		1
								2
								3
				14,054.00		14,054.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						12,278.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
14,054.00		14,054.00		379,458.00		443,955.00		29
								30
								31
								32
								33
								34
								35
202.97		202.97		9,945.30		10,757.62		36
				405.93		405.93		37
								38
				202.96		406.37		39
202.97		202.97		10,148.27		10,757.18		40
								41
								42
								43
				202.96	1,350	406.37	15,537	44
				202.96	1,350	406.37	15,537	45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		2010	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	762.00			
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Other Purchases-See notes				
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	762.00			
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2011		2012		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						762.00		1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
						762.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/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 Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	Not applicable					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)]	Total Amount of Charges	Costs Recognised During Year	WRITTEN OFF DURING YEAR		Balance at End of Year
				Account Charged	Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
21	Big Stone II cancelled project	12,981,726	12,981,726			12,981,726
22	(South Dakota PUC approval					
23	date February 11, 2010					
24	North Dakota PSC and Minnesota					
25	PUC authorization pending)					
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	12,981,726	12,981,726			12,981,726

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	Spiritwood Delivery Facility	64,618	456	68,840	456
3	Pillsbury Wind Delivery Facility	9,707	456	10,976	456
4	Manitoba Hydro Delivery Facility	3,135	456	4,297	456
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Big Stone II Interconnect Facility	54,332	456	56,680	456
23	Veblen Wind Interconnect Facility	72,024	456	73,766	456
24	Morris WInd Interconnect Facility	43,355	456	45,659	456
25	Burr Wind Interconnect Facility	76,415	456	79,202	456
26	Tamarac Wind Interconnect Facility	28,224	456	28,548	456
27	Toronto Wind Interconnect Facility	122,157	456	123,757	456
28	Pillsbury Wind Interconnect Fac	134,695	456	139,865	456
29	Herman Wind Facility Study	2,997	456	4,340	456
30	Harvey Glenboro Short Circuit Stdy	679	456	846	456
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Deferred Income Tax Adjustments					
2	Due to SFAS109 on:					
3	Property Related Items	7,000,198		282	1,663,371	5,336,827
4	Non Property Related Items	93,596	13,869	190	2,799	104,666
5						
6						
7	Asset Retirement Obligation Capitalized					
8	Hoot Lake Plant	655,896	99,846			755,742
9	Big Stone Plant	130,674	52,203			182,877
10	Coyote Station	597,789	110,860			708,649
11	Wind Generation - Langdon	52,547	54,712			107,259
12	Wind Generation - Ashtabula		42,413			42,413
13	Wind Generation - Luverne		11,428			11,428
14						
15	Derivatives-Marked to Market Losses	1,162,321	17,898,170	244	11,446,858	7,613,633
16	MN MISO Costs Deferred	526,360		555	274,623	251,737
17	ND MISO Costs Deferred	823,167	550,661	555	282,698	1,091,130
18	ESSRP	4,535,042	560,923	228.3	274,846	4,821,119
19						
20	Pension	59,955,424	12,920,892	228.3	901,614	71,974,702
21						
22	Rider Recovery - MN	3,044,541	8,301,301		6,022,333	5,323,509
23						
24	Rate Case Expense Deferral	1,456,884	725,000	407.3	489,048	1,692,836
25						
26	Rider Recovery - ND	2,009,025	4,400,966		5,843,688	566,303
27						
28	Holding Co. Formation		271,000	407.3	22,858	248,142
29						
30	MISO RSG		167,530	555	167,530	
31						
32	Asset Based Margin Sharing		329,768			329,768
33						
34	MN Transmission Revenue Rider		528,481		108,353	420,128
35						
36	Pension Plan FAS 106		2,074,897			2,074,897
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	82,043,464	49,114,920		27,500,619	103,657,765

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 12/31/2009	2009/Q4

FOOTNOTE DATA

Schedule Page: 232 Line No.: 22 Column: d
Accounts 440, 442, 444, and 445 were debited.

Schedule Page: 232 Line No.: 26 Column: d
Accounts 440, 442, 444, and 445 were debited.

Schedule Page: 232 Line No.: 34 Column: d
Accounts 440, 442, 444, and 445 were debited.

Name of Respondent Otter Tail Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Conservation Improvement					
2	Programs - MN	265,056	4,395,630	908	2,733,372	1,927,314
3						
4	Energy Efficiency					
5	Program - SD	10,076	205,681	908	258,864	-43,107
6						
7	Conservation Improvement					
8	Programs - ND	4,550		908	4,550	
9						
10	EUIC Project		24,010			24,010
11						
12	Deferred Cost - Big Stone					
13	Plant Jurisdiction					
14	(Amort. period 22-1/2 years)					
15	North Dakota	57,624		406	40,675	16,949
16	South Dakota	5,202		406	3,673	1,529
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	342,508				1,926,695

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Property Insurance Reserve		
3	Workman's Compensation Reserve	190,317	191,026
4	Medical Insurance Reserve		
5	Injuries and Damages Reserve	176,757	176,766
6	See Note Below	77,555,732	112,547,543
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	77,922,806	112,915,335
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)	77,922,806	112,915,335

Notes

NOTE: Continued From Above

Post Retirement Benefits	14,578,112	15,383,310
Executive Supplemental Pension	7,235,133	4,565,664
Reserve for Bad Debts	272,867	373,569
Accrued Vacation Pay	1,320,417	1,311,686
Capitalized Int. on Construction	3,331,624	4,040,457
Post Employment Benefits	1,175,066	1,104,233
Corporate Insurance Reserve	1,374	1,374
Nonqualified Retirement Savings	(109,592)	299,115
Gain From Breck Sale	231,087	231,087
Reserve for Loan Pools	75,552	55,013
Gain on Reacquired Bonds	14	14
Capitalized A & G	5,633,023	6,046,049
Customer Rebates Capitalized	73,321	59,623
Asbestos Removal Costs Capitalized	10,639	8,491
Stock Incentives	108,812	133,200
Stock Options	(14,996)	(14,996)
Mapleton Land	31,061	14,526
CIAC Capitalized	282,878	260,245
Big Stone II Land	23,539	23,539
Unicap Adjustment	0	45,310
Medicare Part D	249,809	257,123
Executive Stock Incentive Plan	(363,894)	(264,012)
Affordable Housing	12,088	497
Charitable Contributions	127,378	347,731
Severance Settlement	0	69,535
Property Taxes	614,879	610,345
Revenue Sufficiency Guarantee	211,770	0
ND NOL Carryforward	1,643,389	7,529,429
Wind Energy Income Tax Credits-ND	35,902,250	58,190,619
SFAS 109 Unamortized ITC	4,946,257	4,965,789
SFAS 109 Recognition of Regulatory Assets (Liab.)	(48,125)	366,082
Wind Production Tax Credit Deferral (Asset)	0	6,532,896
	----------	----------
	77,555,732	112,547,543

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 12/31/2009	2009/Q4

FOOTNOTE DATA

Schedule Page: 234 Line No.: 2 Column: b

The beginning balance on this pages does not agree to the ending balance on the previous year's page. On July 1, 2009 Otter Tail Power Company, 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 (formerly known as Otter Tail Holding Company). The ending balance on the previous year's page included amounts from the parent company. This page, including the beginning balance, does not include any amounts from the parent company.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201 (Par)			
2	Common Stock	50,000,000	5.00	
3	(National Market System)			
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				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
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42				

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 AS REACQUIRED STOCK (Account 217)		HELD BY RESPONDENT IN SINKING AND OTHER FUNDS		Line No.
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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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Parent company investment in Otter Tail Power Company	204,860,891
2	(Result of holding company formation)	
3		
4		
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7		
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40	TOTAL	204,860,891

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	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	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account #221 - Bonds		
2	2011 Series 6.63% Senior Notes	90,000,000	1,239,887
3	2012 Variable Series Pollution Control	10,400,000	168,364
4	2017 Series Pollution Control Refund-BSP	5,185,000	460,639
5	2022 Series Pollution Control Refund-CYT	20,790,000	2,044,935
6	Senior Unsecured Notes 6.47%, Series D	50,000,000	657,739
7			
8	Senior Unsecured Notes 6.37%, Series C	42,000,000	533,850
9			
10	Senior Unsecured Notes 6.15%, Series B	30,000,000	381,237
11	Senior Unsecured Notes 5.95%, Series A	33,000,000	419,420
12	Account 222 - Reacquired Bonds - None		
13	Account 223 - Advances from associated companies		
14	5.33% Notes-Otter Tail Corporation	6,000,000	
15	Issued 7/1/09, MN Public Utilities Commission Authorization		
16	Docket No. E-017/S-09-1018 dated 11/10/09		
17	7.21% Notes-Otter Tail Corporation	2,500,000	
18	Issued 7/1/09, MN Public Utilities Commission Authorization		
19	Docket No. E-017/S-09-1018 dated 11/10/09		
20	7.62% Notes-Otter Tail Corporation	3,000,000	
21	Issued 7/1/09, MN Public Utilities Commission Authorization		
22	Docket No. E-017/S-09-1018 dated 11/10/09		
23	9.35% Notes-Otter Tail Corporation	4,000,000	
24	Issued 7/1/09, MN Public Utilities Commission Authorization		
25	Docket No. E-017/S-09-1018 dated 11/10/09		
26	Account 224 Other Long Term Debt		
27	Variable series 2011 Wind Develop - Luverne (term loan)	75,000,000	1,928,906
28	Issued 5/22/09, MN Public Utilities Commission Authorization		
29	Docket No. E-017/S-09-1018 dated 11/10/09		
30			
31			
32			
33	TOTAL	371,875,000	7,834,977

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
12/27/01	12/01/11	01/01/02	12/01/11	90,000,000	5,189,094	2
12/15/93	12/01/12	12/01/93	12/01/12	10,400,000	367,633	3
09/26/01	09/01/17	10/01/01	09/01/17	5,125,000	239,553	4
09/26/01	09/01/22	10/01/01	09/01/22	20,400,000	995,584	5
08/20/07 &	08/20/37	08/20/07	08/20/37	50,000,000	3,073,250	6
10/01/07						7
08/20/07 &	08/20/27	08/20/07	08/20/27	42,000,000	2,675,400	8
10/01/07						9
10/01/07	08/20/22	10/01/07	08/20/22	30,000,000	1,845,000	10
10/01/07	08/20/17	10/01/07	08/20/17	33,000,000	1,963,500	11
						12
						13
	NA			6,000,000	159,900	14
						15
						16
	NA			2,500,000	90,125	17
						18
						19
	NA			3,000,000	114,300	20
						21
						22
	NA			4,000,000	187,002	23
						24
						25
						26
05/22/09	05/01/11	05/22/09	05/01/11	58,000,000	1,712,121	27
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						32
				354,425,000	18,612,462	33

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 12/31/2009	2009/Q4

FOOTNOTE DATA

Schedule Page: 256 Line No.: 32 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 field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	34,078,812
2		
3		
4	Taxable Income Not Reported on Books	
5	Interest Capitalized on Construction	2,744,415
6	Net Gain from Property Retirements	723,920
7	Miscellaneous Taxable Items	9,000
8	Conservation Improvement Programs	-1,609,075
9	Deductions Recorded on Books Not Deducted for Return	
10	Add Back Federal Income Taxes (Includes Deferreds & ITC Adj.)	349,403
11	Provisions for Reserves	7,806,500
12	Miscellaneous Unallowed Deductions	7,593,552
13		
14	Income Recorded on Books Not Included in Return	
15	Tax Exempt Interest	9,303
16	Equity in Earnings of Subsidiaries	
17	Wind Rider Revenue	836,246
18	Miscellaneous Income Not Taxable	4,216,005
19	Deductions on Return Not Charged Against Book Income	
20	Excess Tax Depreciation Over Book Depreciation	96,822,379
21	Removal Costs	3,029,927
22	Charges to Reserves	5,281,080
23	Leveraged ESOP Deduction	1,952,402
24	Sec 481(a) Cap to Repair Basis Adjustments 2001-2009	42,618,532
25	Miscellaneous Other Deductions	5,865,680
26		
27	Federal Tax Net Income	-108,935,027
28	Show Computation of Tax:	
29	Federal Tax (Line 27 x 35%)	-38,127,259
30	Tax (Credits) and Adjustments	-596,981
31	Prior Period Adjustments	-3,475,802
32	Total Federal Income Tax	-42,200,042
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44		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/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 consolidatd Federal Income Tax Return for the year 2009. The other members of the affiliated group and their respective federal income tax provisions are as follows:

1	Varistar Corporation	585,937
2	DMI Industries, Inc.	1,491,379
3	Aerial Contractors, Inc.	1,687,714
4	Moorhead Electric, Inc.	(153,814)
5	DMS Health Technologies, Inc.	324,088
6	DMS Imaging, Inc.	(1,626,891)
7	BTD Manufacturing, Inc.	(242,900)
8	Northern Pipe Products, Inc.	(159,540)
9	Otter Tail Energy Services Company	(198,834)
10	E. W. Wylie Corporation	(1,526,774)
11	Vinyltech Corporation	(740,453)
12	T. O. Plastics, Inc.	204,072
13	ShoreMaster, Inc.	(1,441,075)
14	Galva Foam Marine Industries, Inc.	166,155
15	Otter Tail Assurance Limited	834,700
16	Aevenia	(17,851)
17	Overland Mechanical Services, Inc.	(15,059)
18	AC Equipment, Inc.	(84,521)
19	Foley Company	683,160
20	Lynk3 Technologies, Inc.	(724,484)
21	Ventus Energy Systems, Inc.	(1,001,069)
22	Idaho-Pacific Corporation	2,199,789
23	Idaho-Pacific Colorado Corporation	1,821,282
24	Shoreline Industries, Inc.	44,813
25	Aviva Sports, Inc.	(915,363)
26	Miller Welding & Iron Works, Inc.	(1,387,014)
27	Otter Tail Corporation-Corporate	(5,358,115)
	Total	(5,550,668)

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.

Name of Respondent Otter Tail Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL					
2	Income	5,499,826		-1,934,424	3,565,402	
3	Unemployment	1,222		51,252	51,964	
4	FICA	1		4,549,917	4,549,917	
5						
6	MINNESOTA					
7	Property	4,549,999		4,389,269	4,495,769	
8	Income	659,234		98,025	270,177	
9	Unemployment	2,870		86,992	88,524	
10						
11	NORTH DAKOTA					
12	Property	2,499,998		2,654,859	2,255,861	
13	Income	-2,215,656		1,495,980	-1,143,448	
14	Unemployment	316		12,786	12,864	
15	Coal Conversion	181,676		709,864	703,387	
16						
17	SOUTH DAKOTA					
18	Property	1,500,001		1,140,912	1,320,913	
19						
20	OTHER STATES					
21	Income	50,660		259,322	-36,092	
22	Railcar	34,465		81,156	82,289	
23						
24						
25						
26						
27						
28						
29						
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31						
32						
33						
34						
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36						
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38						
39						
40						
41	TOTAL	12,764,612		13,595,910	16,217,527	

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 (I) 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
		-42,631,443			40,697,019	2
510					51,252	3
1					4,549,917	4
						5
						6
4,443,499		4,389,269				7
487,082		33,468			64,557	8
1,338					86,992	9
						10
						11
2,898,996		2,605,608			49,251	12
423,772		1,457,482			38,498	13
238					12,786	14
188,153		709,864				15
						16
						17
1,320,000		1,140,912				18
						19
						20
346,074					259,322	21
33,332					81,156	22
						23
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						40
10,142,995		-32,294,840			45,890,750	41

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 1 Column: a

The beginning balance on this pages does not agree to the ending balance on the previous year's page. On July 1, 2009 Otter Tail Power Company, 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 (formerly known as Otter Tail Holding Company). The ending balance on the previous year's page included amounts from the parent company. This page, including the beginning balance, does not include any amounts from the parent company.

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

Account 409.2 $431,401; Account 174.0 $40,265,618

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

Account 184

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

Account 184

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

Account 409.2

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

Account 184

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

Account 408.2 $5,559; Account 921 $43,692

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

Account 409.2

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

Account 184

Schedule Page: 262 Line No.: 21 Column: l

Account 409.2

Schedule Page: 262 Line No.: 22 Column: l

Account 151

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%	28,369,454	190	15,703,755	411.4	1,339,464	
3	4%						
4	7%						
5	10%	5,918,246				991,819	
6							
7							
8	TOTAL	34,287,700		15,703,755		2,331,283	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
42,733,745	25 years		2
			3
			4
4,926,427	33-1/3 years		5
			6
			7
47,660,172			8
			9
			10
			11
			12
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			48

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

Schedule Page: 266   Line No.: 5   Column: e

Account 411.4 was allocated $991,146 and Account 411.5 was allocated $673

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Prepaid Electric Revenue	328,599	456	81,164	174,446	421,881
2	Miscellaneous	20,171	107	32,498	12,327	
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
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39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	348,770		113,662	186,773	421,881

Name of Respondent Otter Tail Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

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

3. Use footnotes as required.

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

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	167,388,250	62,778,553	8,617,390
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	167,388,250	62,778,553	8,617,390
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	167,388,250	62,778,553	8,617,390
10	Classification of TOTAL			
11	Federal Income Tax	141,709,425	52,407,203	6,899,827
12	State Income Tax	25,678,825	10,371,350	1,717,563
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
	120,128	182.3	1,584,416	190	5,496,314	225,341,183	2
							3
							4
	120,128		1,584,416		5,496,314	225,341,183	5
							6
							7
							8
	120,128		1,584,416		5,496,314	225,341,183	9
							10
	99,501		1,310,963		5,496,314	191,302,651	11
	20,627		273,453			34,038,532	12
							13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) _ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

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

Adjustment due to SFAS 109.

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

Adjustment due to Deferred Tax Liability - Wind.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Accum. Deferred Income Tax			
4	Other Utility Operations	2,797,419	6,426,419	1,380,076
5				
6	Accum. Deferred Income Tax			
7	Nonutility & Other	7,426		
8				
9	TOTAL Electric (Total of lines 3 thru 8)	2,804,845	6,426,419	1,380,076
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)	2,804,845	6,426,419	1,380,076
20	Classification of TOTAL			
21	Federal Income Tax	1,354,598	5,694,082	1,159,989
22	State Income Tax	1,450,247	732,337	220,087
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						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
		See note	13,058,718	See note	15,348,086	10,133,130	4
							5
							6
1,256,731	485,180					778,977	7
							8
1,256,731	485,180		13,058,718		15,348,086	10,912,107	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
1,256,731	485,180		13,058,718		15,348,086	10,912,107	19
							20
1,040,684	401,774		10,804,929		12,699,178	8,421,850	21
216,047	83,406		2,253,789		2,648,908	2,490,257	22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) _ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

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

The beginning balance on this page does not agree to the ending balance on the previous year's page. On July 1, 2009 Otter Tail Power Company, 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 (formerly known as Otter Tail Holding Company). The ending balance on the previous year's page included amounts from the parent company. This page, including the beginning balance, does not include any amounts from the parent company.

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

Adjustments due to SFAS 109. Credits to Account 228.3 - $12,773,770; Account 219 - $213,742; and Account 190 - $71,206

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

Debits to Account 182.3 - $14,380,252; Account 254 - $833,730; and Account 184 - $134,104

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Deferred Income Tax Adjustments Due to	4,942,953	190	510,879	533,210	4,965,284
2	SFAS 109					
3						
4						
5	Minnesota Portion of Gain on Sale of Wahpeton	139,408	407.4	5,576		133,832
6	Division Office (Amortization period: 34 years)					
7						
8	Regulatory Liabilities - Derivatives		175	9,696,152	9,919,966	223,814
9						
10	Hoot Lake Plant - Asset Retirement Obligation	3,214,883	108	28,975	41,809	3,227,717
11						
12	Big Stone Plant - Asset Retirement Obligation	5,921,383	108	76,013	92,426	5,937,796
13						
14	Coyote Station - Asset Retirement Obligation	2,954,358	108	76,917		2,877,441
15						
16	Qualified Pension Plan	833,729	182.3	1,455,420	621,691	
17						
18	Margin Sharing - SD				13,993	13,993
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	18,006,714		11,849,932	11,223,095	17,379,877

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	98,163,970	97,567,111
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	114,728,959	115,499,407
5	Large (or Ind.) (See Instr. 4)	64,974,908	72,686,119
6	(444) Public Street and Highway Lighting	3,097,273	3,063,290
7	(445) Other Sales to Public Authorities	2,469,672	2,531,032
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	283,434,782	291,346,959
11	(447) Sales for Resale	12,578,961	23,708,437
12	TOTAL Sales of Electricity	296,013,743	315,055,396
13	(Less) (449.1) Provision for Rate Refunds	1,318,497	3,715,982
14	TOTAL Revenues Net of Prov. for Refunds	294,695,246	311,339,414
15	Other Operating Revenues		
16	(450) Forfeited Discounts	557,298	594,458
17	(451) Miscellaneous Service Revenues	337,444	338,533
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	661,628	649,983
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	11,092,526	11,613,963
22	(456.1) Revenues from Transmission of Electricity of Others	432,905	442,793
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	13,081,801	13,639,730
27	TOTAL Electric Operating Revenues	307,777,047	324,979,144

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
1,296,779	1,257,641	101,703	101,675	2
				3
1,593,811	1,558,950	26,496	26,529	4
1,285,151	1,357,006	50	51	5
27,117	27,121	411	415	6
41,519	41,189	607	611	7
				8
				9
4,244,377	4,241,907	129,267	129,281	10
1,957,534	4,729,086			11
6,201,911	8,970,993	129,267	129,281	12
				13
6,201,911	8,970,993	129,267	129,281	14

Line 12, column (b) includes $ -6,521,502 of unbilled revenues.

Line 12, column (d) includes -3,686 MWH relating to unbilled revenues

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

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

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

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

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

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

Description of Revenue	Amount
All others (under $250,000 each)	$337,444
Total	$337,444

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

Description of Revenue	Amount
Sale of steam	$ 2,186,501
MISO tariff revenue	2,204,000
Integrated transmission deficiency payments	3,747,651
All others (under $250,000 each)	2,954,374
Total	$11,092,526

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Not applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential-440					
2	Residential Service					
3	R-01/9.01	888,019	78,045,731	94,959	9,352	0.0879
4						
5	Residential Service (Ctrl Demand)					
6	R-03/9.02	164,619	10,303,482	6,371	25,839	0.0626
7						
8	Water Heating (Controlled)					
9	R-91/14.01	46,419	2,850,666	17,894	2,594	0.0614
10				-17,894		
11	Controlled Service					
12	I-01,02,03,04/14.04,14.05,14.4,					
13	14.06.14.07	193,410	7,977,347	11,161	17,329	0.0412
14				-11,161		
15	Fixed Time of Delivery Service					
16	I-04/14.07	2,558	91,261	186	13,753	0.0357
17				-186		
18	Outdoor lighting-energy only					
19	M-41/11.03	61	4,340	5	12,200	0.0711
20				-5		
21	Outdoor Lighting					
22	M-42/11.04	4,292	498,930	321	13,371	0.1162
23				-321		
24	Small power producer rider					
25	P-01,09/12.01		16	2		
26				-2		
27	SUBTOTAL Billed	1,299,378	99,771,773	101,330	12,823	0.0768
28	Unbilled Rev (See Instr. 6)	-2,599	-1,607,803			0.6186
29	TOTAL - 440	1,296,779	98,163,970	101,330	12,798	0.0757
30						
31	Column D Lines 9, 13, 16,					
32	19, 22 & 25					
33	Customers are also served under					
34	other residential service.					
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,248,063	289,956,284	131,135	32,395	0.0683
42	Total Unbilled Rev.(See Instr. 6)	-3,686	-6,521,502	0	0	1.7693
43	TOTAL	4,244,377	283,434,782	131,135	32,366	0.0668

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3	Commercial & Industrial-442					
4	General Service					
5	G-01/10.01,10.02	772,986	66,862,609	23,718	32,591	0.0865
6						
7	General Service (Ctrl Demand)					
8	G-02	5,393	348,962	52	103,712	0.0647
9						
10	Electric Climate Control					
11	G-93	44,109	3,278,505	481	91,703	0.0743
12						
13	Farm Service					
14	F-61/9.03	70,465	5,214,298	2,719	25,916	0.0740
15						
16	Large Commercial Service					
17	C-02/10.03	944,253	59,216,252	581	1,625,220	0.0627
18						
19	Large Com Srv (Real Time Pricng)					
20	C-03/14.02	62,104	2,898,358	1	62,104,000	0.0467
21						
22	Large Gen. Srv. (Off Peak Rider)					
23	C-04	11,378	803,972	4	2,844,500	0.0707
24						
25	Large Gen. Srv. (Time of Use)					
26	C-09/10.05	628,857	32,148,244	69	9,113,870	0.0511
27						
28	Large Gen. Srv. Rider					
29	C-12/14.03	58,576	2,313,265	13	4,505,846	0.0395
30						
31	Water heating (controlled)					
32	R-91/14.01	2,231	132,801	602	3,706	0.0595
33				-602		
34						
35						
36						
37	Column D Line 32					
38	Customers are also served					
39	under other commercial service.					
40						
41	TOTAL Billed	4,248,063	289,956,284	131,135	32,395	0.0683
42	Total Unbilled Rev.(See Instr. 6)	-3,686	-6,521,502	0	0	1.7693
43	TOTAL	4,244,377	283,434,782	131,135	32,366	0.0668

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4	Commercial and industrial - cntd					
5	Controlled service					
6	I-01, 02, 03,04/14.04,14.05,14.4,					
7	14.06,14.07	210,637	7,271,488	3,681	57,223	0.0345
8				-3,681		
9	Fixed time of delivery service					
10	I-04/14.07	20,755	674,548	407	50,995	0.0325
11				-407		
12	Bulk interruptible service					
13	I-06/14.12	3,982	178,968	1	3,982,000	0.0449
14						
15	Irrigation service					
16	M-03-11.02	5,016	284,584	253	19,826	0.0567
17						
18	Commercial time of use					
19	M-04/10.04	20,430	942,915	124	164,758	0.0462
20						
21	Outdoor lighting-energy only					
22	M-41/11.03	643	44,273	79	8,139	0.0689
23				-79		
24	Outdoor lighting					
25	M-42,51/11.04	15,144	1,712,891	407	37,209	0.1131
26				-407		
27	Standby service					
28	P-13/11.01	121	21,922	3	40,333	0.1812
29						
30	Residential service					
31	R-01/9.01	270	21,331	12	22,500	0.0790
32						
33	Residential service (ctrl demand)					
34	R-03/9.02	2,554	151,956	74	34,514	0.0595
35						
36						
37	Column D, lines 7,10,22, & 25					
38	Customers are also served under					
39	other commerical service.					
40						
41	TOTAL Billed	4,248,063	289,956,284	131,135	32,395	0.0683
42	Total Unbilled Rev.(See Instr. 6)	-3,686	-6,521,502	0	0	1.7693
43	TOTAL	4,244,377	283,434,782	131,135	32,366	0.0668

Name of Respondent Otter Tail Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3	Commercial and industrial - conti					
4	Small power producer rider					
5	P-01,09/12.01		-3,267	11		
6				-11		
7	SUBTOTAL Billed	2,879,904	184,518,875	28,105	102,469	0.0641
8	Unbilled Rev (See Instr. 6)	-942	-4,815,008			5.1115
9	TOTAL - 442	2,878,962	179,703,867	28,105	102,436	0.0624
10						
11	Streetlighting - 444					
12	Outdoor lighting-energy only					
13	M-41/11.03	4,459	309,914	176	25,335	0.0695
14				-176		
15	Outdoor lighting					
16	M-42,51/11.04	22,607	2,798,159	411	55,005	0.1238
17	Subtotal billed	27,066	3,108,073	411	65,854	0.1148
18	Unbilled Revenue	51	-10,800			-0.2118
19	TOTAL - 444	27,117	3,097,273	411	65,978	0.1142
20						
21	Other Public Authority-445					
22	Pumping and sirens					
23	M-54,59/11.05,11.06	41,715	2,557,563	1,289	32,362	0.0613
24	Unbilled Revenue	-196	-87,891			0.4484
25	TOTAL - 445	41,519	2,469,672	1,289	32,210	0.0595
26						
27	Revenue from Fuel Adjustment					
28	Clause is reported in footnote.					
29						
30	Column D, Lines 3 & 11					
31	Customers are also served under					
32	other commercial service.					
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,248,063	289,956,284	131,135	32,395	0.0683
42	Total Unbilled Rev.(See Instr. 6)	-3,686	-6,521,502	0	0	1.7693
43	TOTAL	4,244,377	283,434,782	131,135	32,366	0.0668

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

Schedule Page: 304.3 Line No.: 27 Column: a

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

Residential - 440	
R-01 Residential service	$ 8,845,342
R-03 Residential service (control demand)	2,287,978
R-91 Water heating (controlled)	446,706
I-03 Controlled service	154,964
M-41 Outdoor lighting - energy only	136
Total residential	11,735,126
Commercial and industrial - 442	
G-01 General service	8,062,693
G-02 General service (control demand)	104,191
G-93 Electric climate control	961,370
F-61 Farm service	526,031
C-02 Large commercial service	9,616,174
C-03 Large commercial service (real-time pricing)	359,052
C-04 Large general service (off-peak rider)	178,156
C-09 Large general service (time of use)	793,497
C-12 Large general service rider	243,630
I-03 Controlled service	342,983
M-03 Irrigation service	(6,800)
M-04 Commercial time of use	48,752
M-41 Outdoor lighting - energy only	909
R-01 Residential service	3,438
R-03 Residential service (control demand)	34,770
R-91 Water heating (controlled)	20,177
Total commercial and industrial	21,289,023
Miscellaneous	
Streetlighting - 444	
M-41 Outdoor lighting - energy only	8,485
Other pubic authority - 445	378,052
Total miscellaneous	386,537
Total	$ 33,410,686

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	RQ SALES					
2	Badger, SD	RQ	144	.198	NA	NA
3	Newfolden, MN	RQ	174	.614	NA	NA
4	Nielsville, MN	RQ	175	.035	NA	NA
5	Shelly, MN	RQ	176	.203	NA	NA
6						
7						
8	NON-RQ SALES					
9	American Electric Power Service	OS	180	NA	NA	NA
10	AmerenUE	OS	180	NA	NA	NA
11	Black Hills Power and Light	OS	180	NA	NA	NA
12	Cargill Power Markets, LLC	OS	180	NA	NA	NA
13	DTE Energy Trading, Inc.	OS	180	NA	NA	NA
14	Fortis Energy Marketing and Trading	OS	180	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Otter Tail Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Great River Energy	OS	180	NA	NA	NA
2	Integrys Energy Services Inc	OS	180	NA	NA	NA
3	Lighthouse Energy Trading Company	OS	180	NA	NA	NA
4	Manitoba Hydro Electric Board	OS	180	NA	NA	NA
5	Minnesota Municipal Power Agency	OS	180	NA	NA	NA
6	Minnesota Power	OS	180	NA	NA	NA
7	Missouri River Energy Services	OS	180	NA	NA	NA
8	Northern States Power Company	OS	180	NA	NA	NA
9	NorthPoint Energy Solutions Inc.	OS	180	NA	NA	NA
10	Omaha Public Power District	OS	180	NA	NA	NA
11	Powerex Corp	OS	180	NA	NA	NA
12	Rainbow Energy Marketing Corp	OS	180	NA	NA	NA
13	Sempra Energy Trading Corporation	OS	180	NA	NA	NA
14	Southwestern Public Service	OS	180	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Tenaska Power Services Co.	OS	180	NA	NA	NA
2	The Energy Authority	OS	180	NA	NA	NA
3	Transalta Energy Marketing	OS	180	NA	NA	NA
4	Western Area Power Administration	OS	180	NA	NA	NA
5	Western Resources	OS	180	NA	NA	NA
6	RBC Capital Markets Corporation	OS	180	NA	NA	NA
7	Midwest ISO Automatic Reserve Sharing	OS	181	NA	NA	NA
8	Midwest ISO Energy Market	OS	180	NA	NA	NA
9	Non-asset based sales	OS	181	NA	NA	NA
10						
11	See Footnote					
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
564	10,752	19,270	5,007	35,029	2
2,455	35,992	83,899	21,069	140,960	3
79	2,663	2,704	761	6,128	4
773	14,209	26,396	7,013	47,618	5
					6
					7
					8
76,300	554,285	2,269,755		2,824,040	9
5,200		351		351	10
17,166		479,615		479,615	11
17,000		619,920		619,920	12
152,200		354,229		354,229	13
29,600		-53,570		-53,570	14
3,871	63,616	132,269	33,850	229,735	
1,953,663	554,285	11,794,941	0	12,349,226	
1,957,534	**617,901**	**11,927,210**	**33,850**	**12,578,961**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
38,800		37,049		37,049	1
143,520		1,627,773		1,627,773	2
800		27,600		27,600	3
4,000		17,804		17,804	4
19,200		667,000		667,000	5
49,200		1,434,480		1,434,480	6
12,662		402,396		402,396	7
261,695		4,930,792		4,930,792	8
9,380		234,940		234,940	9
7,243		95,208		95,208	10
25,600		910,400		910,400	11
69,194		1,650,215		1,650,215	12
18,400		519,600		519,600	13
384		8,892		8,892	14
3,871	63,616	132,269	33,850	229,735	
1,953,663	554,285	11,794,941	0	12,349,226	
1,957,534	**617,901**	**11,927,210**	**33,850**	**12,578,961**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
5,600		110,289		110,289	1
20,140		699,994		699,994	2
2,400		7,297		7,297	3
26,838		962,220		962,220	4
5,600		8,832		8,832	5
497,600		2,216,072		2,216,072	6
		3,611		3,611	7
952,937		12,345,614		12,345,614	8
-514,996		-20,793,437		-20,793,437	9
					10
					11
					12
					13
					14
3,871	63,616	132,269	33,850	229,735	
1,953,663	554,285	11,794,941	0	12,349,226	
1,957,534	**617,901**	**11,927,210**	**33,850**	**12,578,961**	

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

Lines 2-5 are fuel adjustment charges.

Schedule Page: 310.2 Line No.: 9 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 and 426.5, as appropriate. This amount represents the non-asset based cost of forward energy sales.

Schedule Page: 310.2 Line No.: 11 Column: a

MAPP Transmission Service Charges for Non-RQ sales is $62,959.

Name of Respondent Otter Tail Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,563,188	1,541,216
5	(501) Fuel	57,802,065	67,354,090
6	(502) Steam Expenses	2,742,854	3,146,222
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,450,072	2,386,966
10	(506) Miscellaneous Steam Power Expenses	5,010,782	4,388,519
11	(507) Rents	1,273	9,811
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	69,570,234	78,826,824
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	728,813	717,396
16	(511) Maintenance of Structures	563,648	646,627
17	(512) Maintenance of Boiler Plant	6,254,624	6,280,633
18	(513) Maintenance of Electric Plant	3,066,190	2,935,656
19	(514) Maintenance of Miscellaneous Steam Plant	1,187,668	1,100,270
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	11,800,943	11,680,582
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	81,371,177	90,507,406
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	30,609	33,070
45	(536) Water for Power		
46	(537) Hydraulic Expenses	26,519	7,801
47	(538) Electric Expenses	68,468	34,145
48	(539) Miscellaneous Hydraulic Power Generation Expenses	972	156
49	(540) Rents	1,188	385
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	127,756	75,557
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	4,861	1,216
54	(542) Maintenance of Structures	7,836	8,108
55	(543) Maintenance of Reservoirs, Dams, and Waterways	382,892	236,803
56	(544) Maintenance of Electric Plant	94,427	30,884
57	(545) Maintenance of Miscellaneous Hydraulic Plant	6,407	29,126
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	496,423	306,137
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	624,179	381,694

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	69,865	66,149
63	(547) Fuel	1,969,522	5,191,639
64	(548) Generation Expenses	1,316,537	1,119,221
65	(549) Miscellaneous Other Power Generation Expenses	126,949	88,459
66	(550) Rents	316,004	109,158
67	TOTAL Operation (Enter Total of lines 62 thru 66)	3,798,877	6,574,626
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	22,841	13,920
70	(552) Maintenance of Structures	18,170	13,705
71	(553) Maintenance of Generating and Electric Plant	564,174	940,205
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	9,366	27,369
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	614,551	995,199
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	4,413,428	7,569,825
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	52,943,739	56,334,634
77	(556) System Control and Load Dispatching	375,883	309,643
78	(557) Other Expenses	683,621	1,883,395
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	54,003,243	58,527,672
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	140,412,027	156,986,597
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	460,657	423,941
84	(561) Load Dispatching		
85	(561.1) Load Dispatch-Reliability	57,499	68,854
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,545,955	2,631,747
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	509,028	378,217
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	294	
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	205,452	168,764
94	(563) Overhead Lines Expenses	339,387	239,309
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	138,817	41,661
97	(566) Miscellaneous Transmission Expenses	1,071,888	1,095,095
98	(567) Rents	14,082	71,274
99	TOTAL Operation (Enter Total of lines 83 thru 98)	5,343,059	5,118,862
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	448,117	383,511
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	100,844	8,618
104	(569.2) Maintenance of Computer Software	652,361	876,117
105	(569.3) Maintenance of Communication Equipment	73,089	132,393
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,170,883	1,068,756
108	(571) Maintenance of Overhead Lines	1,183,741	1,864,421
109	(572) Maintenance of Underground Lines	220	1,230
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,629,255	4,335,046
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	8,972,314	9,453,908

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	1,246,679	1,226,192
117	(575.3) Transmission Rights Market Facilitation	182,668	235,837
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)	1,429,347	1,462,029
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software	285,036	40,174
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)	285,036	40,174
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	1,714,383	1,502,203
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	424,186	397,506
135	(581) Load Dispatching	297,804	356,114
136	(582) Station Expenses	184,208	153,356
137	(583) Overhead Line Expenses	479,539	247,451
138	(584) Underground Line Expenses	1,194,797	1,173,207
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	939,070	1,022,451
141	(587) Customer Installations Expenses	424,428	354,144
142	(588) Miscellaneous Expenses	2,295,846	2,464,143
143	(589) Rents	257,463	343,226
144	TOTAL Operation (Enter Total of lines 134 thru 143)	6,497,341	6,511,598
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	884,229	805,567
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	760,920	677,918
149	(593) Maintenance of Overhead Lines	3,703,900	4,416,717
150	(594) Maintenance of Underground Lines	864,050	830,403
151	(595) Maintenance of Line Transformers	8,816	
152	(596) Maintenance of Street Lighting and Signal Systems	997,606	1,098,665
153	(597) Maintenance of Meters	481,294	440,213
154	(598) Maintenance of Miscellaneous Distribution Plant	135,862	
155	TOTAL Maintenance (Total of lines 146 thru 154)	7,836,677	8,269,483
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	14,334,018	14,781,081
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	102,637	164,509
160	(902) Meter Reading Expenses	4,835,906	4,545,580
161	(903) Customer Records and Collection Expenses	5,020,253	5,033,027
162	(904) Uncollectible Accounts	865,500	945,025
163	(905) Miscellaneous Customer Accounts Expenses	325,296	326,543
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	11,149,592	11,014,684

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	574,681	708,791
168	(908) Customer Assistance Expenses	4,265,847	4,358,788
169	(909) Informational and Instructional Expenses	313,265	281,894
170	(910) Miscellaneous Customer Service and Informational Expenses	45,021	54,712
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	5,198,814	5,404,185
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	570,988	649,883
176	(913) Advertising Expenses	46,811	89,415
177	(916) Miscellaneous Sales Expenses	307,239	317,792
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	925,038	1,057,090
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	16,708,167	16,591,281
182	(921) Office Supplies and Expenses	4,331,435	4,767,718
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	1,350,187	1,467,767
185	(924) Property Insurance	1,508,889	1,523,294
186	(925) Injuries and Damages	1,416,527	1,783,852
187	(926) Employee Pensions and Benefits	3,070,046	1,905,237
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	2,009,549	3,493,762
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	732,698	903,894
192	(930.2) Miscellaneous General Expenses	738,532	609,869
193	(931) Rents	191,687	180,782
194	TOTAL Operation (Enter Total of lines 181 thru 193)	32,057,717	33,227,456
195	Maintenance		
196	(935) Maintenance of General Plant	1,282,404	2,317,681
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	33,340,121	35,545,137
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	216,046,307	235,744,885

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

Schedule Page: 320 Line No.: 84 Column: b

$714,136 of the year-to-date expense recorded in Accounts 561 and 569 is designated as Account 561.BA expense.

Schedule Page: 320 Line No.: 84 Column: c

$983,202 of the year-to-date expense recorded in Accounts 561 and 569 is designated as Account 561.BA expense.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	AmerenUE	OS		NA	NA	NA
2	American Electric Power Service Corp	OS		NA	NA	NA
3	Black Hills Power and Light	OS		NA	NA	NA
4	PB Energy	OS		NA	NA	NA
5	Cargill Power Markets, LLC	OS		NA	NA	NA
6	Constellation Energy Commodities Group	OS		NA	NA	NA
7	DTE Energy Trading, Inc.	OS		NA	NA	NA
8	DTE Energy Trading, Inc.	SF		25	NA	NA
9	Fortis Energy Marketing and Trading	OS		NA	NA	NA
10	Great River Energy	OS		NA	NA	NA
11	Great River Energy	SF		50	NA	NA
12	Integrys Energy Services Inc	OS		NA	NA	NA
13	Manitoba Hydro Electric Board	SF		50	NA	NA
14	Manitoba Hydro Electric Board	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)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Mid-American Energy Company	OS		NA	NA	NA
2	Minnesota Municipal Power Agency	OS		NA	NA	NA
3	Minnesota Power	OS		NA	NA	NA
4	Minnkota Power Cooperative	OS		NA	NA	NA
5	Missouri River Energy Services	OS		NA	NA	NA
6	Northern States Power Company	OS		NA	NA	NA
7	Northern States Power Company	SF		25	NA	NA
8	NorthPoint Energy Solutions Inc	OS		NA	NA	NA
9	Omaha Public Power District	OS		NA	NA	NA
10	Powerex	OS		NA	NA	NA
11	Rainbow Energy Marketing Corp.	OS		NA	NA	NA
12	Sempra Energy Trading Corporation	OS		NA	NA	NA
13	Tenaska Power	OS		NA	NA	NA
14	The Energy Authority	OS		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Transalta Energy Marketing	OS		NA	NA	NA
2	WE Energies	SF		50	NA	NA
3	Western Area Power Administration	OS		NA	NA	NA
4	Western Area Power Administration-WEC	OS		NA	NA	NA
5	Western Resources	OS		NA	NA	NA
6	Wisconsin Public Power Inc	SF		35	NA	NA
7	Beltrami Electric Cooperative	RQ		NA	NA	NA
8	Nodak Rural Electric Cooperative	RQ		NA	NA	NA
9	P K M Electric Cooperative	RQ		NA	NA	NA
10	NorthWestern Energy - NLE	RQ		NA	NA	NA
11	Red Lake Rural Electric Cooperative	RQ		NA	NA	NA
12	Lake Region Rural Electric Cooperative	RQ		NA	NA	NA
13	Cass County Electric Cooperative	RQ		NA	NA	NA
14	Sioux Valley Energy	RQ		NA	NA	NA
	Total					

Name of Respondent Otter Tail Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	City of Perham	RQ		NA	NA	NA
2	Montana Dakota Utility - Mountrail	RQ		NA	NA	NA
3	Dakota Magic Casino	RQ		NA	NA	NA
4	State Auto Insurance	RQ		NA	NA	NA
5	Kindred School	RQ		NA	NA	NA
6	Fleet Farm	RQ		NA	NA	NA
7	Valley Queen Cheese	OS		NA	NA	NA
8	Stevens Community Medical	OS		NA	NA	NA
9	City of Detroit Lakes	OS		NA	NA	NA
10	American Crystal Sugar	OS		NA	NA	NA
11	Energy Maintenance Service	OS		NA	NA	NA
12	Hendricks Wind 1	OS		NA	NA	NA
13	Borderline Wind	OS		NA	NA	NA
14	Univ. of MN - Morris	OS		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	FPL Energy ND II, LLC	OS		NA	NA	NA
2	Langdon Wind, LLC	OS		NA	NA	NA
3	MN Co Generation	OS		NA	NA	NA
4	ND Co Generation	OS		NA	NA	NA
5	SD Co Generation	OS		NA	NA	NA
6	RBC Capital Markets Corporation	OS		NA	NA	NA
7	MISO Transmission Service Charge	OS		NA	NA	NA
8	MAPP Transmission Service Charge	OS		NA	NA	NA
9	WAPA Schedule and Dispatch	OS		NA	NA	NA
10	Xcel Energy Meter Error	OS		NA	NA	NA
11	Midwest ISO Energy market	OS		NA	NA	NA
12	Control Area Exchange - Net					
13	Non-asset based cost of sales					
14						
	Total					

Name of Respondent Otter Tail Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
10,400				-1,882		-1,882	1
5,728				176,170		176,170	2
400				18,000		18,000	3
800				2,046		2,046	4
11,216				380,024		380,024	5
800				95		95	6
57,200				4,411		4,411	7
			30,000			30,000	8
28,000				-445		-445	9
88,200				233,638		233,638	10
			276,000			276,000	11
43,200				770,903		770,903	12
			1,635,000			1,635,000	13
225,512				15,266,132	-846,252	14,419,880	14
2,763,847			4,082,325	49,443,847	-582,433	52,943,739	

Name of Respondent Otter Tail Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
73,917				2,320,816		2,320,816	1
1,600				52,220		52,220	2
259,650				10,629,664		10,629,664	3
240				4,692		4,692	4
2,586				41,973		41,973	5
133,615				1,953,218		1,953,218	6
			323,250			323,250	7
220				5,640		5,640	8
71,581				1,865,716	308	1,866,024	9
49,600				1,464,000		1,464,000	10
39,179				856,220		856,220	11
5,600				208,000		208,000	12
800				-2,043		-2,043	13
8,623				184,610		184,610	14
2,763,847			4,082,325	49,443,847	-582,433	52,943,739	

Name of Respondent Otter Tail Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
1,600				2,755		2,755	1
			369,200			369,200	2
10,489				241,416	48,149	289,565	3
29,870				862,080		862,080	4
3,600				23,506		23,506	5
			488,250			488,250	6
70,723			429,923	2,931,891	75,393	3,437,207	7
1,343			29,153	49,822	50	79,025	8
3,490			29,628	148,267		177,895	9
19,797			150,770	935,152		1,085,922	10
2,977			32,926	125,086		158,012	11
11				1,488		1,488	12
			262			262	13
52				2,815		2,815	14
2,763,847			4,082,325	49,443,847	-582,433	52,943,739	

Name of Respondent Otter Tail Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
			24,388			24,388	1
8				217		217	2
			39,195			39,195	3
			36,000			36,000	4
			35,460			35,460	5
			17,460			17,460	6
			111,460			111,460	7
			22,800			22,800	8
989			1,200	1,484		2,684	9
154				1,536		1,536	10
145				4,633		4,633	11
2,186				98,366		98,366	12
2,099				62,977		62,977	13
766				32,168		32,168	14
2,763,847			4,082,325	49,443,847	-582,433	52,943,739	

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
63,544				1,899,979		1,899,979	1
75,338				2,954,767		2,954,767	2
114				6,984		6,984	3
515							4
2				25		25	5
727,500				4,052,908		4,052,908	6
					54,302	54,302	7
					65,870	65,870	8
					19,747	19,747	9
-3,525				-39,028		-39,028	10
988,525				30,694,088		30,694,088	11
				-362,659		-362,659	12
-357,132				-31,722,694		-31,722,694	13
							14
2,763,847			4,082,325	49,443,847	-582,433	52,943,739	

Name of Respondent Otter Tail Power Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report 2009/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 8 Column: a
Winter season through April 2009.

Schedule Page: 326 Line No.: 11 Column: a
Winter season through February 2009 and summer season of July and August 2009.

Schedule Page: 326 Line No.: 13 Column: a
Winter and summer season January through December 2009.

Schedule Page: 326 Line No.: 14 Column: l
MHEB PAC Loss Credit

Schedule Page: 326.1 Line No.: 7 Column: a
Winter season through May 2009

Schedule Page: 326.1 Line No.: 9 Column: l
Omaha Public Power District Transmission

Schedule Page: 326.2 Line No.: 2 Column: a
Summer season June through August 2009

Schedule Page: 326.2 Line No.: 3 Column: l
Load Following charge

Schedule Page: 326.2 Line No.: 6 Column: a
Winter and summer season January through December 2009

Schedule Page: 326.2 Line No.: 7 Column: l
Nomination charge

Schedule Page: 326.2 Line No.: 8 Column: l
Interconnection Charge

Schedule Page: 326.4 Line No.: 7 Column: l
Transmission service charge

Schedule Page: 326.4 Line No.: 8 Column: l
Transmission service charge

Schedule Page: 326.4 Line No.: 9 Column: l
Scheduling/dispatch charge

Schedule Page: 326.4 Line No.: 11 Column: a
Midwest ISO Energy Market

Schedule Page: 326.4 Line No.: 12 Column: a
Represents control area exchange as of December 31. These are inadvertant exchanges of electricity between utilities in the exchange area.

Schedule Page: 326.4 Line No.: 13 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 and 426.5, as appropriate. This amount represents the non-asset based cost of forward energy sales.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	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	LFP
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	See Footnote			
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
4	(1)	Badger, SD		1,287	1,232	1
4	(1)	Newfolden, MN		2,569	2,401	2
4	(1)	Nielsville, MN		646	604	3
4	(1)	Shelly, MN		1,800	1,682	4
4	(1)	Fort Totten, ND		257	242	5
4	(1)	Grafton, ND		4,965	4,684	6
4	(1)	Devils Lake, ND		589	550	7
4	(1)	Bottineau, ND		1,092	1,021	8
4	(1)	Wahpeton, ND		8,560	8,038	9
4	(1)	Belcourt, ND		2,695	2,542	10
4	(1)	Oakes, ND		40	38	11
See Footnote	(1)	Various Interconnect		217,470	203,243	12
		(1)		-2,256		13
		(1)		-91,311		14
		(1)		10,466		15
	See Footnote					16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**158,869**	**226,277**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
9,402			9,402	1
25,748			25,748	2
7,944			7,944	3
16,582			16,582	4
1,331			1,331	5
24,483			24,483	6
6,031			6,031	7
11,030			11,030	8
91,664			91,664	9
34,574			34,574	10
873			873	11
	203,243		203,243	12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
229,662	**203,243**	**0**	**432,905**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/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: 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.: 16 Column: f

(1) Various points of interconnect in the integrated system in column f, lines 1-12 and column g, lines 13-15

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1	Not applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Otter Tail Power Co.	FNS					31,262	31,262
2	Western Area Power Admn	NF		328			679	679
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL			328			31,941	31,941

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

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

Changes in lines 1 through 2 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 2009.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	173,643
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	47,669
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	107,549
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	43,509
6	Director Fees and Expenses	198,726
7	Misc. labor not prvided for elsewhere	167,436
8		
9		
10		
11		
12		
13		
14		
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16		
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43		
44		
45		
46	TOTAL	738,532

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

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

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

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			554,715		554,715
2	Steam Production Plant	9,128,887	9,711			9,138,598
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	119,331				119,331
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	9,638,205	36,184			9,674,389
7	Transmission Plant	4,214,042				4,214,042
8	Distribution Plant	9,463,184				9,463,184
9	Regional Transmission and Market Operation					
10	General Plant	2,388,235				2,388,235
11	Common Plant-Electric					
12	TOTAL	34,951,884	45,895	554,715		35,552,494

B. Basis for Amortization Charges

The $554,715 is amortization of:

Franchises and Consents (302)
$47,884 for hydro plant licenses with a remaining life of 11.54 years at a 3.68% rate.

Miscellaneous Intangible Plan (303)
$506,831 for computer software with a 5-year service life at a 20% rate.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production-						
13	Big Stone Plant						
14	311	6,189		-8.80	2.24	SQ	16.14
15	312	29,295		-8.80	3.07	SQ	16.15
16	314	15,542		-8.80	3.98	SQ	16.15
17	315	2,481		-8.80	2.36	SQ	16.14
18	316	1,021		-8.60	2.95	SQ	16.15
19							
20	Steam Production						
21	Hoot Lake Plant						
22	311 - Units 2,3	140		-12.50	1.32	SQ	11.32
23	312 - Units 2,3	12,843		-12.50	4.58	SQ	11.33
24	314 - Units 2,3	1,780		-12.50	2.58	SQ	11.33
25	315 - Units 2,3	38		-12.50	1.27	SQ	11.32
26	316 - Units 2,3	342		-12.40	4.61	SQ	11.33
27							
28	Steam Production						
29	Coyote Plant						
30	311	10,893		-5.00	1.89	SQ	20.88
31	312	34,360		-5.00	2.13	SQ	20.89
32	314	7,851		-5.00	2.30	SQ	20.89
33	315	2,900		-5.00	1.86	SQ	20.88
34	316	942		-4.70	2.76	SQ	20.90
35	STEAM PRODUCTION						
36	SUBTOTAL	126,617					
37							
38	Hydro Production -						
39	Hoot Lake Hydro						
40	331	2			0.26	SQ	13.24
41	332	7			0.21	SQ	13.24
42	333	19			1.37	SQ	13.26
43	334	9			2.06	SQ	13.26
44	Hydro Production -						
45	Wright Hydro						
46	331	7			2.71	SQ	13.26
47	332	216			4.55	SQ	13.25
48	333	146			4.83	SQ	13.27
49	334	132			5.42	SQ	13.27
50	335	18			2.54	SQ	13.26

Name of Respondent Otter Tail Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13	Hydro Production -						
14	Pisgah Hydro						
15	331	4			2.33	SQ	13.26
16	332	25			1.69	SQ	13.25
17	333	145			6.84	SQ	13.27
18	334	76			5.13	SQ	13.27
19	335	9			3.09	SQ	13.26
20							
21	Hydro Production -						
22	Dayton Hollow Hydro						
23	331				1.67	SQ	13.25
24	332	99			2.37	SQ	13.26
25	333	108			5.90	SQ	13.27
26	334	70			3.94	SQ	13.27
27	335	3			3.03	SQ	13.26
28							
29	Hydro Production -						
30	Taplin Gorge Hydro						
31	331	3			0.54	SQ	13.23
32	332	82			1.70	SQ	13.25
33	333				0.16	SQ	13.22
34	334	2			1.34	SQ	13.25
35	335	29			3.43	SQ	13.27
36							
37	Hydro Production -						
38	Bemidji Hydro						
39	331	85			6.10	SQ	13.27
40	332	78			2.72	SQ	13.26
41	333	220			5.01	SQ	13.27
42	334	1			1.44	SQ	13.23
43	335				1.20	SQ	13.25
44	HYDRO PRODUCTION						
45	SUBTOTAL	1,595					
46							
47							
48							
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Other Production -						
13	Jamestown Peaking #1						
14	341	60		-0.60	2.35	SQ	11.33
15	342	47		-0.60	2.09	SQ	11.32
16	343	1,084		-0.60	3.38	SQ	11.32
17	345	4		-0.60	1.62	SQ	11.32
18	346	35		-0.60	4.95	SQ	11.33
19	Other Production -						
20	Lake Preston Peaking						
21	341	40		-0.90	1.90	SQ	11.32
22	342	62		-0.90	1.91	SQ	11.32
23	343	755		-0.90	2.19	SQ	11.32
24	345	59		-0.90	1.93	SQ	11.32
25	346	4		-0.90	1.54	SQ	11.32
26	Other Production -						
27	Jamestown Peaking #2						
28	341	7		-0.60	4.28	SQ	11.33
29	342	13		-0.60	3.12	SQ	11.32
30	343	1,053		-0.60	2.50	SQ	11.32
31	345	14		-0.60	3.25	SQ	11.33
32	346	8		-0.60	2.51	SQ	11.33
33	Other Production -						
34	Fergus Falls Control Cr						
35	343	376			2.91	SQ	21.85
36	Other Production -						
37	Solway Combustion Turb						
38	341	3,485		-0.10	2.83	SQ	29.32
39	342	837		-0.10	2.85	SQ	29.33
40	343	17,387		-0.10	2.82	SQ	29.32
41	345	1,033		-0.10	2.82	SQ	29.32
42	346	262		-0.10	2.92	SQ	29.33
43	OTHER PRODUCTION						
44	Langdon Wind Energy						
45	341				4.08	S5	24.50
46	342				4.08	S5	24.50
47	343				4.08	S5	24.50
48	344	74,760			3.92	S5	24.50
49	345				4.08	S5	24.50
50	346				4.08	S5	24.50

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	Ashtabula Wind Energy						
13	341				4.00	S5	25.00
14	342				4.00	S5	25.00
15	343				4.00	S5	25.00
16	344	114,950			3.99	S5	25.00
17	345				4.00	S5	25.00
18	346				4.00	S5	25.00
19	Luverne Wind Energy						
20	341				4.00	S5	25.00
21	342				4.00	S5	25.00
22	343				4.00	S5	25.00
23	344				4.00	S5	25.00
24	345				4.00	S5	25.00
25	346				4.00	S5	25.00
26	SUBTOTAL	216,335					
27	Transmission Plant						
28	353	46,952	45.00	-5.00	1.65	R0.5	48.47
29	354	2,524	55.00	-10.00	1.49	R5	42.89
30	355	41,567	55.00	-50.00	2.27	S1.5	45.98
31	356	38,780	55.00	-30.00	2.04	S1.5	43.04
32	358	18	40.00	-5.00	3.76	S4	7.37
33	SUBTOTAL	129,841					
34	Distribution Plant -						
35	362	35,447	35.00	5.00	2.39	S-.5	27.51
36	364	27,508	60.00	-75.00	2.63	R3	47.17
37	365	13,420	58.00	-100.00	3.22	R3	40.73
38	366		50.00		3.71	R4	26.98
39	367	30,325	35.00	-5.00	2.85	R4	21.35
40	368	49,857	40.00	50.00	1.46	R0.5	23.47
41	369	-330	48.00	-150.00	4.81	S5	30.58
42	369.1	18,285	40.00	-20.00	2.56	R4	32.34
43	370	12,536	33.00		2.85	S0.5	21.77
44	370.1	6,496	20.00		6.15	L3	12.12
45	370.2	755	5.00		20.00	Amortized	
46	371		25.00		38.61	R3	2.59
47	371.2	2,811	19.00	10.00	3.85	L0	16.74
48	373	2,093	16.00	-5.00	5.16	L2	10.31
49	SUBTOTAL	199,203					
50							

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	General Plant -						
13	390	15,211	45.00	10.00	1.93	L1	36.34
14	390.1	3,493		-5.00	3.07	SQ	21.84
15	390.2	413		-5.00	3.36	SQ	17.09
16	390.3	2,257		-5.00	2.38	SQ	26.49
17	391	890	15.00		6.67	Amortized	
18	391.1	538	10.00		10.00	Amortized	
19	391.2	480	10.00		10.00	Amortized	
20	391.5	797	5.00		20.00	Amortized	
21	391.6	743	5.00		20.00	Amortized	
22	392	11,328					
23	Aircraft		7.00	39.00			
24	Autos		5.00	15.00			
25	Light Trucks		10.00	10.00			
26	Heavy Trucks & Semi		10.00	15.00			
27	Tractors (Includes		10.00	15.00			
28	Cranes)						
29	Trailers		15.00	10.00			
30	Portable Oil Purifier		10.00	20.00			
31	Trenchers		10.00	10.00			
32	Misc. Light Equip.		10.00	10.00			
33	Misc. Heavy Equip.		15.00	15.00			
34	393		15.00		6.67	Amortized	
35	394	1,559	15.00		6.67	Amortized	
36	394.2	615	15.00		6.67	Amortized	
37	395	20	15.00		6.67	Amortized	
38	396	373	15.00	5.00	3.90	L0	16.02
39	397	291	15.00		6.67	Amortized	
40	397.1	469	10.00		10.00	Amortized	
41	397.2	1,620	15.00		6.67	Amortized	
42	397.3	66	10.00		10.00	Amortized	
43	397.4	938	25.00	5.00	4.01	R4	14.48
44	SUBTOTAL	42,101					
45	TOTAL	715,692					
46							
47	SUBACCOUNTS USED						
48							
49							
50							

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FOOTNOTE DATA

Schedule Page: 336.4 Line No.: 47 Column: a

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

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

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

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

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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	118,564		118,564	
3	SD Public Utilities Commission	41,696		41,696	
4	Federal Energy Regulatory Commission	216,449		216,449	
5					
6	Other Expenses:				
7	MN Public Utilities Commission:				
8	MN Rate Case (E017/GR-07-1178)	14,765	147,100	161,865	1,456,884
9	Miscellaneous		36,974	36,974	
10					
11	ND Public Service Commission:				
12	ND Rate Case PU 08 862	89,427	274,306	363,733	
13					
14	Miscellaneous	759	17,186	17,945	
15					
16	SD Public Utilities Commission:				
17	SD Rate Case EL 08 030		236,392	236,392	
18					
19	Miscellaneous		255	255	
20					
21	FERC				
22	ER08-370 (MRES Attachment O)		434,833	434,833	
23	EL07-86 (Midwest ISO RSG Proceedings)		217,244	217,244	
24	ER09-914 (MRES / CPEC)		32,258	32,258	
25	ER10-183 (CWIP Forward looking Attach O)		27,399	27,399	
26	Miscellaneous	600	103,342	103,942	
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	482,260	1,527,289	2,009,549	1,456,884

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REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	118,564					2
Electric	928	41,696					3
Electric	928	216,449					4
							5
							6
							7
Electric	928	161,865	-135,000		445,159	876,725	8
		36,974					9
							10
							11
Electric	928	363,733	500,000		13,889	486,111	12
							13
		17,945					14
							15
							16
Electric	928	236,392	225,000		30,000	195,000	17
							18
Electric	928	255					19
							20
							21
Electric	928	434,833					22
Electric	928	217,244					23
Electric	928	32,258					24
Electric	928	27,399					25
Electric	928	103,942					26
							27
							28
							29
							30
							31
							32
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							36
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							44
							45
		2,009,549	590,000		489,048	1,557,836	46

Name of Respondent Otter Tail Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

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

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

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

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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)

5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
17,576		506	17,576		4
32,309		920	32,309		5
10,214		930.2	10,214		6
80		588	80		7
75		921	75		8
60,254			60,254		9
					10
					11
	8,766	930.2	8,766		12
	38,720	930.2	38,720		13
	38,057	506	38,057		14
	2,850	923	2,850		15
					16
	88,393		88,393		17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
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					37
					38

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	8,136,308		
4	Transmission	3,952,266		
5	Regional Market	1,429,347		
6	Distribution	5,141,488		
7	Customer Accounts	7,179,884		
8	Customer Service and Informational	1,489,371		
9	Sales	717,059		
10	Administrative and General	18,763,962		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	46,809,685		
12	Maintenance			
13	Production	4,815,127		
14	Transmission	2,019,071		
15	Regional Market	41,984		
16	Distribution	5,309,920		
17	Administrative and General	2,018,263		
18	TOTAL Maintenance (Total of lines 13 thru 17)	14,204,365		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	12,951,435		
21	Transmission (Enter Total of lines 4 and 14)	5,971,337		
22	Regional Market (Enter Total of Lines 5 and 15)	1,471,331		
23	Distribution (Enter Total of lines 6 and 16)	10,451,408		
24	Customer Accounts (Transcribe from line 7)	7,179,884		
25	Customer Service and Informational (Transcribe from line 8)	1,489,371		
26	Sales (Transcribe from line 9)	717,059		
27	Administrative and General (Enter Total of lines 10 and 17)	20,782,225		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	61,014,050		61,014,050
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

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DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	61,014,050		61,014,050
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	10,725,320		10,725,320
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	10,725,320		10,725,320
72	Plant Removal (By Utility Departments)			
73	Electric Plant	746,784		746,784
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	746,784		746,784
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock (151)	74,598		74,598
79	Miscellaneous Deferred Debits (186)	799,124		799,124
80	Other Electric Revenue (456)	517,438		517,438
81	Expenses of Nonutility Operations (417.1)	296,221		296,221
82	Exp. for Certain Civic, Political and Related Activity (426.4	55,658		55,658
83	Other Deductions (426.5)	27,481		27,481
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	1,770,520		1,770,520
96	TOTAL SALARIES AND WAGES	74,256,674		74,256,674

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.

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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.

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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 currently available.				
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
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23					
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33					
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38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

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PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

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

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

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

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

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

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

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	43,078	$/MW-Hr	7,086	5,037,857	$/MW-Hr	524,984
2	Reactive Supply and Voltage	117,823	$/MW-Hr	17,674	3,639,635	$/MW-Hr	545,058
3	Regulation and Frequency Response	21,874	$/MW-Hr	15,530	763,433	$/MW-Hr	80,008
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other				2,919	$/MW-Hr	306
8	Total (Lines 1 thru 7)	182,775		40,290	9,443,844		1,150,356

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FOOTNOTE DATA

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

Line 1, Scheduling, System Control and Dispatch does not include $19747 of services purchased from WAPA which was purchased with a "Unit of Measure" of $/Schedule - Day.

Schedule Page: 398 Line No.: 7 Column: e

Other is Generator Regulation and Frequency Response

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	800	13	1000	799	1				
2	February	733	3	800	732	1				
3	March	752	11	1000	751	1				
4	Total for Quarter 1	2,285			2,282	3				
5	April	625	3	800	624	1				
6	May	522	14	900	521	1				
7	June	575	25	1500	574	1				
8	Total for Quarter 2	1,722			1,719	3				
9	July	582	21	1500	581	1				
10	August	618	13	1700	617	1				
11	September	538	16	1600	537	1				
12	Total for Quarter 3	1,738			1,735	3				
13	October	585	15	1200	584	1				
14	November	606	20	900	605	1				
15	December	736	15	1200	735	1				
16	Total for Quarter 4	1,927			1,924	3				
17	Total Year to Date/Year	7,672			7,660	12				

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: Not applicable

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/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)	4,244,377
3	Steam	3,042,503			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	3,871
5	Hydro-Conventional	24,095			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,953,663
7	Other	399,955			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	28
9	Net Generation (Enter Total of lines 3 through 8)	3,466,553	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	13,577
10	Purchases	2,763,847	27	Total Energy Losses	-52,524
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	6,162,992
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	158,869			
17	Delivered	226,277			
18	Net Transmission for Other (Line 16 minus line 17)	-67,408			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	6,162,992			

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-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	690,182	186,612	800	13	1000
30	February	617,458	182,450	733	3	800
31	March	640,998	284,729	752	11	1000
32	April	418,074	122,171	625	3	800
33	May	479,432	225,287	522	14	900
34	June	486,181	192,225	575	25	1500
35	July	497,017	182,451	582	21	1500
36	August	527,329	221,836	618	13	1700
37	September	468,504	142,080	538	16	1600
38	October	422,075	115,665	585	15	1200
39	November	391,009	60,112	606	20	900
40	December	524,733	38,045	736	15	1200
41	TOTAL	6,162,992	1,953,663			

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

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

Includes interchange transactions and losses thereon.

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

Includes interchange transactions and losses thereon.

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: Coyote (b)			Plant Name: Big Stone (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1981			1975		
4	Year Last Unit was Installed	1981			1975		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	144.90			223.15		
6	Net Peak Demand on Plant - MW (60 minutes)	149			256		
7	Plant Hours Connected to Load	6632			8207		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	144			224		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	80			74		
12	Net Generation, Exclusive of Plant Use - KWh	856358745			1587452879		
13	Cost of Plant: Land and Land Rights	718662			374603		
14	Structures and Improvements	31545992			22600399		
15	Equipment Costs	123050099			110854337		
16	Asset Retirement Costs	101890			82358		
17	Total Cost	155416643			133911697		
18	Cost per KW of Installed Capacity (line 17/5) Including	1072.5786			600.0972		
19	Production Expenses: Oper, Supv, & Engr	492302			487991		
20	Fuel	12084802			32580504		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	1428984			558564		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	554426			935608		
26	Misc Steam (or Nuclear) Power Expenses	764485			2527747		
27	Rents	438			835		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	219474			287156		
30	Maintenance of Structures	153843			203876		
31	Maintenance of Boiler (or reactor) Plant	2385118			1877011		
32	Maintenance of Electric Plant	884762			38463		
33	Maintenance of Misc Steam (or Nuclear) Plant	388782			252341		
34	Total Production Expenses	19357416			39750096		
35	Expenses per Net KWh	0.0226			0.0250		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal-Subbit	Oil	TDF
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	Tons
38	Quantity (Units) of Fuel Burned	698152	3660	0	986042	1812	6038
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	6889	140000	0	8376	140000	15000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	16.520	72.450	0.000	31.230	71.400	20.000
41	Average Cost of Fuel per Unit Burned	16.530	80.430	0.000	31.140	106.600	20.000
42	Average Cost of Fuel Burned per Million BTU	1.200	13.679	0.000	1.859	18.129	0.667
43	Average Cost of Fuel Burned per KWh Net Gen	0.014	0.000	0.000	0.021	0.000	0.000
44	Average BTU per KWh Net Generation	11237.000	0.000	0.000	10580.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

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

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Lake Preston* (b)			Plant Name: *Solway* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1978			2003		
4	Year Last Unit was Installed	1978			2003		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	24.10			44.00		
6	Net Peak Demand on Plant - MW (60 minutes)	26			47		
7	Plant Hours Connected to Load	22			1046		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	20			49		
10	When Limited by Condenser Water	20			49		
11	Average Number of Employees	1			2		
12	Net Generation, Exclusive of Plant Use - KWh	260077			26361425		
13	Cost of Plant: Land and Land Rights	12339			89809		
14	Structures and Improvements	194155			4201573		
15	Equipment Costs	3766473			23569783		
16	Asset Retirement Costs	0			0		
17	Total Cost	3972967			27861165		
18	Cost per KW of Installed Capacity (line 17/5) Including	164.8534			633.2083		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	112285			1478077		
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	16502			409605		
26	Misc Steam (or Nuclear) Power Expenses	1250			71657		
27	Rents	0			5344		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	2455			4780		
30	Maintenance of Structures	4			16943		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	74484			443726		
33	Maintenance of Misc Steam (or Nuclear) Plant	2317			6588		
34	Total Production Expenses	209297			2436720		
35	Expenses per Net KWh	0.8048			0.0924		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil			Natural Gas	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Barrels			MMBTU	Barrels	
38	Quantity (Units) of Fuel Burned	1210	0	0	302076	127	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	140000	0	0	303700	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	4.580	65.060	0.000
41	Average Cost of Fuel per Unit Burned	92.780	0.000	0.000	4.580	75.520	0.000
42	Average Cost of Fuel Burned per Million BTU	15.779	0.000	0.000	4.580	12.843	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.432	0.000	0.000	0.056	0.000	0.000
44	Average BTU per KWh Net Generation	27364.000	0.000	0.000	11487.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/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: *Big Stone (Cont.)* (d)	Plant Name: *Hoot Lake* (e)	Plant Name: *Jamestown* (f)	Line No.
	Steam	Gas Turbine	1
	Conventional	Conventional	2
	1959	1976	3
	1964	1978	4
0.00	129.40	48.20	5
0	144	54	6
0	13251	133	7
0	0	0	8
0	144	42	9
0	0	42	10
0	49	1	11
0	598691600	754588	12
0	477820	24614	13
0	6134877	244250	14
0	48741386	7068295	15
0	130498	0	16
0	55484581	7337159	17
0.0000	428.7835	152.2232	18
0	414432	0	19
0	14715064	379160	20
0	0	0	21
0	765077	0	22
0	0	0	23
0	0	0	24
0	960038	27751	25
0	1172806	252	26
0	0	100	27
0	0	0	28
0	222183	0	29
0	205922	1224	30
0	1992495	0	31
0	2144525	36462	32
0	548495	0	33
0	23141037	444949	34
0.0000	0.0387	0.5897	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
RRM			Coal	Oil		Oil			36
Tons			Tons	Barrels		Barrels			37
2322	0	0	370078	1803	0	3827	0	0	38
7187	0	0	9319	140000	0	140000	0	0	39
8.500	0.000	0.000	39.190	80.140	0.000	83.790	0.000	0.000	40
8.500	0.000	0.000	38.900	80.300	0.000	99.080	0.000	0.000	41
0.591	0.000	0.000	2.087	13.657	0.000	16.850	0.000	0.000	42
0.000	0.000	0.000	0.025	0.000	0.000	0.502	0.000	0.000	43
0.000	0.000	0.000	11477.000	0.000	0.000	29820.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/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
		0.0000			0.0000			0.0000	18
		0			0			0	19
		0			0			0	20
		0			0			0	21
		0			0			0	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		0			0			0	26
		0			0			0	27
		0			0			0	28
		0			0			0	29
		0			0			0	30
		0			0			0	31
		0			0			0	32
		0			0			0	33
		0			0			0	34
		0.0000			0.0000			0.0000	35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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

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

Schedule Page: 402 Line No.: 11 Column: f

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

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. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			1
			2
			3
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			35
			36
			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydro:					
2	Hoot Lake	1914	1.00	0.8	5,048	562,931
3	Wright	1922	0.40	0.5	3,082	864,031
4	Pisgah	1917	0.52	0.7	5,186	416,504
5	Dayton Hollow	1909	0.97	1.1	6,704	866,060
6	Taplin Gorge	1925	0.56	0.5	4,075	685,695
7	Bemidji	-	0.74	0.2		647,974
8						
9	Internal Combustion:					
10	Fergus Control Center	1995	1.83	2.0	24	591,638
11	Diesel Generators		2.26	2.3		
12						
13	Wind Turbine Plants					
14	Langdon	2007	40.50	40.5	154,387	77,780,377
15	Ashtabula	2008	48.00	48.0	155,965	117,679,960
16	Luverne	2009	49.50	50.0	56,585	72,173,104
17						
18						
19						
20						
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46						

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 Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
703,664	12,529		37,117	-		2
1,728,062	13,081		42,106	-		3
595,006	10,629		52,097	-		4
787,327	14,397		62,201	-		5
1,371,389	12,458		61,037	-		6
3,239,870	54,928		233,353	-		7
						8
						9
295,819	2,809		9,503	Oil		10
				Oil		11
						12
						13
1,920,503	585,794					14
2,451,666	598,057		241			15
1,443,462	63,375					16
						17
						18
						19
						20
						21
						22
						23
						24
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						43
						44
						45
						46

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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Center	Maple River	345.00	345.00	Alum Tower	48.00		1
2								
3								
4	Fergus Falls	Henning	230.00	230.00	Wood H	20.00		1
5	Fergus Falls	Wahpeton	230.00	230.00	Wood H	29.00		1
6	Wahpeton	Hankinson	230.00	230.00	Wood H	25.00		1
7	Hankinson	Forman	230.00	230.00	Wood H	36.00		1
8	Forman	Ellendale	230.00	230.00	Wood H	48.00		1
9	Audubon (W 1/10)	Badoura	230.00	230.00	Wood H	6.00		1
10	Audubon	Maple River	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)	Gary	230.00	230.00	Wood H	15.00		1
15	Harvey	Coal Creek	230.00	230.00	Wood H	72.00		1
16	Underwood	Coal Creek	230.00	230.00	Wood H	3.00		1
17	Rugby	Balta	230.00	230.00	Steel H	40.00		1
18								
19								
20								
21		Total	115.00	115.00	Wood H	438.00		
22		Total	115.00	115.00	SWP	413.00		
23		Total	69.00	69.00		206.00		
24								
25								
26		Total	41.60	41.60	SWP	3,639.00		
27		Total	41.60	41.60	Underground	1.00		
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	5,149.00		15

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) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
		5,458,744	5,458,744					1
								2
								3
	6,339	549,602	555,941					4
	5,935	675,257	681,192					5
		475,142	475,142					6
		765,639	765,639					7
		1,133,627	1,133,627					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
		608,325	608,325					14
		10,184,441	10,184,441					15
		402,272	402,272					16
		7,619,960	7,619,960					17
								18
								19
								20
	74,783	5,927,728	6,002,511					21
	49,282	15,062,337	15,111,619					22
		6,028,867	6,028,867					23
								24
								25
	4,953	92,522,383	92,527,336					26
		72,673	72,673					27
								28
								29
								30
								31
								32
								33
								34
				4,964,696	1,373,004	14,082	6,351,782	35
	141,292	151,964,809	152,106,101	4,964,696	1,373,004	14,082	6,351,782	36

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) __ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

Schedule Page: 422 Line No.: 35 Column: m

Columns m, n, o, and p detail by line not available.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Belcourt	Belcourt West	1.30	Single Pole	20.00	1	1
2	Rugby 115 kv Sub	Rugby Northwest	0.30	Single Pole		1	1
3	Rugby 115 kv Sub	Rugby Northwest	0.70	Single Pole		2	2
4	Carrington 535	Sykeston 511	16.00	Single Pole	20.00	1	1
5	Lone Tree - 473 Ave.	Lone Tree - 476 Ave.	3.20	Single Pole	16.00	2	2
6	Lone Tree - 476 Ave.	Egan	1.75	Single Pole	21.00	1	1
7	Egan Sub	Trent Sub	2.00	Single Pole	21.00	1	1
8	Green Valley 69	Green Valley	1.00	Single Pole	22.00	1	1
9	Appleton 115	Canby 115	40.30	Single Pole	21.00	1	1
10	Canby 115	Sam Jones Rural	0.70	Single Pole	17.00	2	2
11	Canby 115	Sam Jones Rural	3.67	Single Pole	22.00	1	1
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
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41							
42							
43							
44	TOTAL		70.92		180.00	14	14

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
266	ACSR	3102	69		81,436	54,290		135,726	1
266	ACSR	3050	41			11,791		11,791	2
266	ACSR	3345	41			27,511		27,511	3
10rt2	ACSR	3050	41		7,710	15,420		23,130	4
10rt2	ACSR	Vert-1 side	41		189,613	81,263		270,876	5
10rt2	ACSR	3102	41		102,100	43,757		145,857	6
10rt2	ACSR	3102	41		256,912	110,105		367,017	7
10rt2	ACSR	3102	41		141,891	84,696		226,587	8
10rt2	ACSR	3651	115		262,544	174,461	-22,916	414,089	9
10rt2	ACSR	3102	41		38,808	35,587		74,395	10
10rt2	ACSR	3102	41		203,745	186,830	-4,123	386,452	11
									12
									13
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					1,284,759	825,711	-27,039	2,083,431	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Bemidji, MN - 115 kv - 63246	Transmission	115.00	69.00	13.80
2			41.60	2.40	
3			15.70	2.40	
4	Big Stone, SD Highway 12 - 63215	Transmission	115.00	41.60	
5	Big Stone, SD Plant - 63314	Transmission	22.90	230.00	
6			230.00	115.00	13.80
7			23.60	13.80	
8	Browns Valley, MN - 230 kv (Peever) - 63325	Transmission	230.00	41.60	
9			41.60	4.16	
10	Buffalo, ND - 345 kv - 63258	Transmission	345.00	115.00	43.00
11			41.60	2.40	
12			41.60	2.40	
13	Canby, MN - 115 kv - 63211	Transmission	115.00	41.60	
14			41.60	4.16	
15	Cass Lake, MN - 115 kv - 63347	Transmission	115.00	41.60	69.00
16	Clearbrook, MN - 115 kv - 63241	Transmisison	115.00	41.60	
17			41.60	13.80	
18	Crookston, MN - 115 kv - 63249	Transmission	115.00	41.60	
19			115.00	41.60	
20	Devils Lake, ND - East 115 kv - 63265	Transmission	115.00	41.60	
21			41.60	2.40	
22	Devils Lake, ND - SW 115 kv - 224	Transmission	115.00	41.60	
23	Donaldson, MN - 115 kv - 63255	Transmission	115.00	41.60	
24			115.00	41.60	
25			41.60	6.90	
26	Fertile, MN - 115 kv - 63250	Transmission	115.00	41.60	
27			41.60	2.30	
28	Finley, ND - Pickert 115 kv - 711	Transmission	230.00	72.00	41.60
29			41.60	2.40	
30	Forman, ND - Forman 230 kv - 63363	Transmission	230.00	115.00	41.60
31			41.60	4.16	
32			41.60	12.50	
33	Hetland, SD - 115 kv - 63209	Transmission	115.00	41.60	
34	Fergus Falls, MN - Hoot Lake - 63123	Transmission	14.40	41.60	
35	Fergus Falls, MN - Hoot Lake 115 kv - 63223	Transmission	14.40	115.00	
36			14.40	115.00	
37			115.00	43.80	
38			115.00	12.50	
39	Jamestown, ND - 345 kv - 63369	Transmission	345.00	115.00	43.00
40			41.60	2.40	

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			41.60	2.40	
2	Jamestown, ND - Peaking Plant 115 kv - 6327	Transmission	115.00	41.60	
3			41.60	12.50	
4			41.60	7.20	
5	Lake Preston, SD - Peaking Plant - 7857	Transmission	41.60	12.50	
6			41.60	4.16	
7			12.50	4.16	
8	Maple River, ND - 345 kv - 66792	Transmission	345.00	230.00	13.80
9	Mapleton, ND - 115 kv - 63203	Transmission	115.00	41.60	
10	Marietta, MN - 115 kv - 63213	Transmission	115.00	41.60	
11			41.60	2.40	
12	Northwood, ND - 115 kv - 63282	Transmission	115.00	41.60	
13	Oakes, ND - 230 kv - 63362	Transmission	230.00	41.60	
14			41.60	4.16	
15	Ortonville, MN - 115 kv - 63216	Transmission	115.00	41.60	
16			41.60	0.40	
17	Pelican Rapids, MN - 115 kv - 63234	Transmission	115.00	41.60	
18	Plummer, MN - 115 kv - 7967	Transmission	115.00	41.60	
19	Rugby, ND - 230 kv - 63373	Transmission	230.00	115.00	13.80
20	Solway, MN - 115 kv	Transmission	115.00	13.80	
21	Toronto, SD - 115 kv - 63210	Transmission	115.00	41.60	
22			41.60	2.40	
23	Wahpeton, ND - North 115 kv - 63230	Transmission	115.00	12.50	
24	Wilton, MN	Transmission	230.00	115.00	13.80
25			41.60	2.40	
26	Winger, MN	Transmission	230.00	115.00	
27			41.60	7.20	
28			41.60	2.40	
29					
30	Transmission Subtotal:		6907.90	2818.26	307.20
31	Transmission Subs Under 10,000 kva				
32	Transmission Total		6907.90	2818.26	307.20
33					
34					
35	Bemidji, MN Airport	Distribution	41.60	12.50	
36	Bemidji, MN 25th Street	Distribution	69.00	12.50	
37	Bemidji, MN Nymore	Distribution	69.00	12.50	
38	Bemidji, MN Potlatch	Distribution	69.00	12.50	
39	Casselton, ND	Distribution	41.60	12.50	
40	Casselton, ND Ethanol Plant	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	Clearbrook, MN Pipeline	Distribution	115.00	12.50	
2	Cooperstown, ND	Distribution	41.60	12.50	
3	Crookston, MN Southmain	Distribution	41.60	12.50	
4	Crookston, MN Parkview	Distribution	41.60	12.50	
5	Crookston, MN South Main	Distribution	41.60	12.50	
6	Dawson, MN Dawson Mills	Distribution	115.00	12.50	
7	Devils Lake, ND Downtown	Distribution	41.60	4.16	
8	Enderlin, ND	Distribution	115.00	12.50	
9	Fairmount, ND	Distribution	115.00	12.50	
10	Fergus Falls, MN Edgetown	Distribution	115.00	12.50	
11	Gwinner, ND	Distribution	115.00	12.50	
12	Harvey, ND Northwest	Distribution	115.00	12.50	
13	Itasca, MN Minnesota Pipeline	Distribution	115.00	4.16	
14	Jamestown, ND Southwest	Distribution	41.60	12.50	
15	Jamestown, ND Downtown	Distribution	115.00	12.50	
16	Jamestown, ND Potato	Distribution	115.00	12.50	
17	Jamestown, ND North	Distribution	115.00	12.50	
18	Lake Norden, SD Dairy	Distribution	41.60	12.50	
19	Lisbon, ND Town	Distribution	115.00	12.50	
20	Mahnomen, MN	Distribution	115.00	12.50	
21	Mapleton, ND	Distribution	115.00	41.60	
22	Milbank, SD South	Distribution	41.60	12.50	
23	Milbank, SD Northwest	Distribution	41.60	12.50	
24	Morris, MN South	Distribution	115.00	12.50	
25	Morris, MN Northeast	Distribution	41.60	12.50	
26	Oakes, ND	Distribution	41.60	12.50	
27	Perham, MN	Distribution	115.00	12.50	
28	Pelican Rapids, MN Turkey Plant	Distribution	41.60	12.50	
29	Rosholt, SD	Distribution	41.60	12.50	
30	Rugby, ND South	Distribution	41.60	12.50	
31	Spiritwood, ND Ladish	Distribution	115.00	12.50	
32	Spiritwood, ND Ladish	Distribution	115.00	41.60	
33	Wahpeton, ND Northwest	Distribution	41.60	12.50	
34	Wheaton, MN South	Distribution	115.00	12.50	
35	Distribution Subtotal:		3214.20	541.52	
36	Distribution Under 10,000 kva				
37	Distribution Total		3214.20	541.52	
38	Transmission From Above				
39	Transmission & Distribution				
40					

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
19	1					1
	3					2
4	1					3
45	1					4
460	1					5
233	1					6
39	1					7
26	1					8
5	1					9
112	1					10
1	3					11
	1					12
27	1					13
5	1					14
19	1					15
10	1					16
	3					17
39	1					18
56	1					19
34	1					20
	3					21
57	1					22
10	1					23
10	1					24
3	1					25
10	1					26
1	3					27
60	1					28
2	3					29
140	1					30
2	1					31
	1					32
45	1					33
10	1					34
84	1					35
60	1					36
30	1					37
37	1					38
224	2					39
1	3					40

Name of Respondent Otter Tail Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2009	Year/Period of Report End of 2009/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
3	1					1
56	1					2
28	2					3
5	1					4
28	1					5
4	1					6
1	3					7
672	2					8
20	1					9
10	1					10
1	3					11
13	1					12
34	1					13
	3					14
22	1					15
1	1					16
13	1					17
34	1					18
125	1					19
80	1					20
45	1					21
	1					22
24	2					23
140	1					24
1	3					25
140	1					26
1	3					27
	1					28
						29
3421	96					30
						31
3421	96					32
						33
						34
14	1					35
15	1					36
14	1					37
11	1					38
10	1					39
47	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
22	2					1
10	1					2
15	1					3
10	1					4
25	1					5
10	1					6
10	1					7
19	2					8
10	3					9
37	1					10
20	2					11
14	1					12
11	1					13
14	1					14
14	1					15
14	1					16
14	1					17
12	1					18
14	1					19
14	1					20
20	1					21
10	1					22
25	1					23
12	3					24
12	1					25
10	3					26
28	2					27
10	1					28
10	1					29
10	1					30
50	2					31
16	1					32
20	2					33
12	1					34
665	53					35
886	954					36
1551	1007					37
3421						38
4972						39
						40

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) X An Original (2) _ A Resubmission	12/31/2009	2009/Q4

FOOTNOTE DATA

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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.

Column C, D, and E data is reported in KVA.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Assiciated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Capital/construction projects	Otter Tail Corporation	107	107,869
3	Insurance	Otter Tail Corporation	165	1,717,549
4	Unamortized debt expense	Otter Tail Corporation	181	157,251
5	Misc deferred debits	Otter Tail Corporation	186	797
6	Bonds	Otter Tail Corporation	221	45,000
7	Injuries and damages	Otter Tail Corporation	228.2	41,161
8	Stock purchase plan - customers	Otter Tail Corporation	232	213,345
9	Accrued interest	Otter Tail Corporation	237	7,833,259
10	Employee voluntary deductions	Otter Tail Corporation	242	750,481
11	Debt discount and expense	Otter Tail Corporation	428	432
12	Dividends - preferred stock	Otter Tail Corporation	437	367,750
13	Dividends - common stock	Otter Tail Corporation	438	33,845,743
14	Corporate allocated A&G expense	Otter Tail Corporation	500	6,401
15	Corporate allocated A&G expense	Otter Tail Corporation	506	1,327
16	Corporate allocated A&G expense	Otter Tail Corporation	593	490
17	Corporate allocated A&G expense	Otter Tail Corporation	907	1,587
18	Corporate allocated A&G expense	Otter Tail Corporation	908	1,384
19	Corporate allocated A&G expense	Otter Tail Corporation	912	10,000
20	**Non-power Goods or Services Provided for Affiliate**			
21	Printing, design & mailing services	Otter Tail Corporation	417	1,383,659
22	Other deductions	Otter Tail Corporation	426.5	1,514,646
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Corporate allocated A&G expense	Otter Tail Corporation	920	2,308,025

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Power Company	(1) [X] An Original (2) [ ] A Resubmission	12/31/2009	End of 2009/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Assiciated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Corporate allocated A&G expense	Otter Tail Corporation	921	514,578
4	Corporate allocated A&G expense	Otter Tail Corporation	923	757,515
5	Corporate allocated A&G expense	Otter Tail Corporation	924	1,815
6	Corporate allocated A&G expense	Otter Tail Corporation	925	43,743
7	Corporate allocated A&G expense	Otter Tail Corporation	928	16,881
8	Corporate allocated A&G expense	Otter Tail Corporation	930.1	12,516
9	Corporate allocated A&G expense	Otter Tail Corporation	930.2	341,763
10	Corporate allocated A&G expense	Otter Tail Corporation	931	88,741
11	Corporate allocated A&G expense	Otter Tail Corporation	935	169,127
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
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42				

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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.

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