THIS FILING IS

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

Form 1 Approved
OMB No. 1902-0021
(Expires 7/31/2008)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

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 Corporation	End of 2007/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 Corporation	02 Year/Period of Report End of 2007/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 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* (218) 739-8291	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

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 Kevin Moug	03 Signature Kevin Moug	04 Date Signed *(Mo, Da, Yr)* / /
02 Title Chief Financial Officer & Treasurer		

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 Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/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".

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".

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".

Stockholders' Reports Check appropriate box:

[ ] Four copies will be submitted

[ ] No annual report to stockholders is prepared

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

CONTROL OVER RESPONDENT

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Varistar Corporation	Holding Company	100	(7)
2				
3	Aerial Contractors, Inc.	Construction & Maintenance	100	(8)
4		Power & Communication Lines		
5				
6	BTD Manufacturing, Inc.	Metal Stamping	100	(1)
7				
8	DMI Industries, Inc.	Metal Fabrication &	100	(1)
9		Steel Flame Cutting		
10				
11	DMS Health Technologies, Inc. aka DMS	Sales & Services of Medical	100	(1)
12	Health Group	Imaging Equipment		
13				
14	DMS Imaging, Inc.	Diagnostic Medical Svc	100	(2)
15				
16	DMS Leasing Corporation	Inactive at this time	100	(2)
17				
18	Moorhead Electric, Inc.	Electrical & Utility	100	(8)
19		Contractor		
20				
21	Northern Pipe Products, Inc.	PVC Pipe Mfg.	100	(1)
22				
23	Otter Tail Energy Services Company	Energy Services	100	(7)
24				
25	E.W. Wylie Corporation	Transportation Company	100	(1)
26				
27	Vinyltech Corporation	PVC Pipe Manufacturing	100	(1)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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.
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1				
2	T.O. Plastics, Inc.	Plastic Products Mfg.	100	(1)
3				
4	ShoreMaster, Inc.	Waterfront Equipment Mfg.	100	(1)
5				
6	Galva Foam Marine Industries, Inc.	Waterfront Equipment Mfg.	100	(3)
7				
8	Midwest Construction Services, Inc.	Holding Company	100	(1)
9				
10	Foley Company	Mechanical & prime contract.	100	(1)
11				
12	Overland Mechanical Services Inc	Plumbing, Heating, Air Cond	100	(6)
13				
14	Lynk3 Technologies, Inc	Data Servicing Group	100	(8)
15				
16	AC Equipment, Inc	Fleet Mgmt, Equip Lease &	100	(8)
17		Rental		
18				
19	Ventus Energy Systems, Inc.	Engineering & construction	100	(8)
20		services for renewable energy		
21		industry		
22				
23	Otter Tail Assurance, LTD	Captive Insurance Company	100	(7)
24				
25	Idaho Pacific Holdings, Inc.	Holding Company	100	(1)
26				
27	Idaho Pacific Corporation	Food Ingredient Processor	100	(4)

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1				
2	Idaho Pacific Colorado Corporation	Food Ingredient Processor	100	(4)
3				
4	AWI Acquisition Company Limited	Holding Company	100	(4)
5				
6	Agra West Investments Limited	Food Ingredient Processor	100	(5)
7				
8	Shoreline Industries, Inc.	Waterfront Equipment Mfg.	100	(3)
9				
10	DMS Imaging Partners LLC	Inactive at this time	100	(9)
11				
12	DMS Imaging Partners II LLC	Inactive at this time	100	(9)
13				
14	DMI Canada, Inc.	Metal Fabrication	100	(10)
15				
16	Aviva Sports, Inc.	Waterfront Equipment Mfg	100	(3)
17				
18	ShoreMaster Costa Rica SRL	Waterfront Equipment Mfg	100	(3)
19				
20	Green Hills Energy, LLC	Energy Services	100	(6)
21				
22	Sheridan Ridge I, LLC	Energy Services	100	(6)
23				
24	Sheridan Ridge II, LLC	Energy Services	100	(6)
25				
26				
27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

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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
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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	(1) Subsidiary of Varistar Corporation			
2	(2) Subsidiary of DMS Health Technologies, Inc			
3	(3) Subsidiary of ShoreMaster			
4	(4) Subsidiary of Idaho Pacific Holdings, Inc.			
5	(5) Subsidiary of Agra West Investment			
6	Acquisition Company			
7	(6) Subsidiary of Otter Tail Energy Services			
8	Company			
9	(7) Subsidiary of Otter Tail Corporation			
10	(8) Subsidiary of Midwest Construction Srvcs.			
11	(9) Subsidiary of DMS Imaging, Inc.			
12	(10) Subsidiary of DMI Industries, Inc.			
13				
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16				
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22				
23				
24				
25				
26				
27				

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 *	John D. Erickson	1,989,900
2			
3	Executive Vice President and Chief Operating Officer *	Lauris N. Molbert	1,669,596
4			
5	Chief Financial Officer and Treasurer *	Kevin G. Moug	1,056,695
6			
7	Corporate Secretary and General Counsel *	George Koeck	824,913
8			
9	President, Utility**	Charles S. MacFarlane	642,261
10			
11			
12			
13			
14	* Otter Tail Corporation		
15	** Otter Tail Power Company, a division of		
16	Otter Tail Corporation		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	John C. MacFarlane ***	
2	Chariman of the Board of Directors	Fergus Falls, Minnesota
3		
4	Karen M. Bohn ***	Edina, Minnesota
5		
6	Dennis R. Emmen	Fergus Falls, Minnesota
7		
8	John D. Erickson	Fergus Falls, Minnesota
9		
10	Arvid R. Liebe ***	Milbank, South Dakota
11		
12	Edward J. McIntyre	Incline Village, Nevada
13		
14	Joyce Nelson Schuette	Minneapolis, Minnesota
15		
16	Nathan I. Partain *** **	Chicago, Illinois
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18	Gary J. Spies	Fergus Falls, Minnesota
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Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report / /	Year/Period of Report End of 2007/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. On July 5, 2007, two Otter Tail Power customers served from the Walhalla Concrete Jct substation were transferred to Nodak Electric Cooperative. The 2006 revenue from these customers totaled $6,386. Public Service Commission (PSC) authorization was not required for the transfer of these customers.

   On July 12, 2007, eighteen Otter Tail Power customers served from the Olga substation were transferred to Cavalier Rural Electric Cooperative. The 2006 revenue from these customers totaled $9,836. PSC authorization was not required for the transfer of these customers. Otter Tail Power also removed 25 miles of 41.6 kV transmission line associated with the above-mentioned project.

   On October 25, 2007, a farm customer near Marion was transferred to Otter Tail Power's Grand Rapids substation from Dakota Valley Electric Cooperative. Otter Tail Power also removed 25 miles of 41.6 kV transmission line associated with the above-mentioned project.

   On November 20, 2007, an Appleton customer was transferred to Otter Tail Power from Agralite Electric Cooperative. Otter Tail Power also added a 1 mile primary extension associated with the above-mentioned project. A letter was written to the PSC and the release was approved. Approximate revenue from this customer is estimated at $1,000.

6. On October 2, 2007 the Company terminated its $150 million unsecured revolving credit facility which had been available to support borrowings of the Company's nonelectric operations. This credit facility had been outstanding since April 26, 2006.

   On September 1, 2006, the Company entered into a line of credit for $25 million with U.S. Bank National Association. This line created 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. On April 13, 2007 this agreement was amended to increase the commitment from $25 million to $50 million. On August 31, 2007 this agreement was amended to increase the commitment from $50 million to $75 million and to extend the termination of the agreement from September 1, 2007 to September 1, 2008. As of December 31, 2007 no money was borrowed under this credit agreement.

   At closings completed in August 2007 and October 2007, the Company issued $155 million aggregate principal amount of its senior unsecured notes, in a private placement transaction, to the purchasers named in a note purchase agreement (the 2007 Note Purchase Agreement) dated August 20, 2007. These notes were issued in four series: $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017 (the Series A Notes); $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022 (the Series B Notes); $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027 (the Series C Notes); and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (the Series D Notes). On August 20, 2007, $12 million aggregate principal amount of the Series C Notes and $13 million aggregate principal amount of the Series D Notes were issued and sold pursuant to the 2007 Note Purchase Agreement. The remaining $30 million aggregate principal amount of the Series C Notes and $37 million aggregate principal amount of the Series D Notes, as well as the Series A Notes and the Series B Notes, were issued and sold by the Company at a second closing on October 1, 2007.

   In February 2007, the Company entered into a note purchase agreement (the Cascade Note Purchase Agreement) with Cascade Investment L.L.C. (Cascade) pursuant to which the Company agreed to issue to Cascade, in a private placement transaction, $50 million aggregate principal amount 5.778% senior note due November 30, 2017. On December 14, 2007 the note was issued.

   Minnesota Public Utilities Commission authorization given under Docket No. E-017/S-06-219 dated April 27, 2006 and E-017/S-07-364 dated September 17, 2007.

   See Footnotes for more information about short-term and long-term borrowings.

7. None.

8. The average annual increase for nonunion employees was 3.61% effective April 1, 2007. Wages for Local Union 1570 were increased by 3.5% effective September 1, 2007. Wages for Local Union 949, 203, 239, and 524 were increased by 3.5% effective November 1, 2007.

9. None.

10. On February 23, 2007, the Company entered into a note purchase agreement dated February 23, 2007 (the "Note Purchase Agreement") with Cascade Investment L.L.C. ("Cascade"). The Company agreed to issue to Cascade, in a private placement transaction, $50 million aggregate principal amount of the Company's senior notes due November 30, 2017 (the "Notes"). The Notes will bear interest at a rate of 5.778% per annum, subject to adjustment in the event certain ratings assigned to the Company's long-term senior unsecured indebtedness are downgraded below specific levels prior to the closing of the Note purchase. The terms of the Note Purchase Agreement are substantially similar to the terms of the note purchase agreement entered into in connection with the issuance of the Company's $90 million 6.63% senior notes due December 1, 2011. The closing occurred on December 14, 2007. The proceeds of the closing were used to redeem the Company's $50 million 6.375% senior debentures due December 1, 2007. Cascade owns approximately 8.6% of the Company's outstanding common shares as of December 31 2007.

11. (Reserved.)

12. None.

13. On March 26, 2007, Ken Nelson notified the Company of his decision to resign from the Company's Board of Directors effective at the conclusion of the Company's 2007 Annual Meeting of Shareholders on April 9, 2007. Mr. Nelson resigned in order to devote more time to his personal business interests and not because of a disagreement with the Company.

    On April 9, 2007, the Company's Board of Directors elected John D. Erickson, the Company's President and Chief Executive Officer, to serve as a member of the Board of Directors. Mr. Erickson filled the vacancy created by the resignation of Ken Nelson, which was effective at the conclusion of the Company's 2007 Annual Meeting of Shareholders. He will serve for the remainder of that term, which expires on the date of the Company's 2008 Annual Meeting of Shareholders.

    The preferred share purchase rights that have been issued with each common share outstanding since February 15, 1997 expired pursuant to their terms on January 27, 2007.

    As of December 31, 2007, Cascade Investment L.L.C. owns 2,556,499 common shares, and Tontine Partners owns 2,904,282 common shares. The shares have full voting powers.

14. Ratio is not less than 30 percent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	1,028,917,132	930,688,703
3	Construction Work in Progress (107)	200-201	33,772,360	18,502,442
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,062,689,492	949,191,145
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	446,475,444	433,656,959
6	Net Utility Plant (Enter Total of line 4 less 5)		616,214,048	515,534,186
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)		616,214,048	515,534,186
15	Utility Plant Adjustments (116)	122	0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		3,457,886	2,720,965
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,590,324	1,065,382
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	346,183,521	301,299,453
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)		3,022,415	3,314,269
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		18,662,763	16,223,594
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)		369,736,261	322,492,899
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		4,846,287	1,705,474
36	Special Deposits (132-134)		1,376,025	1,598,428
37	Working Fund (135)		22,405	22,880
38	Temporary Cash Investments (136)		22,435,436	7,813,219
39	Notes Receivable (141)		0	129,346
40	Customer Accounts Receivable (142)		15,920,538	21,334,199
41	Other Accounts Receivable (143)		7,805,379	4,881,276
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		623,602	600,404
43	Notes Receivable from Associated Companies (145)		27,545,560	67,186,577
44	Accounts Receivable from Assoc. Companies (146)		1,450,489	4,542,228
45	Fuel Stock (151)	227	8,798,580	7,467,638
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	13,775,037	12,401,519
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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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)		1,150,786	1,290,180
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)		32,501,444	23,931,125
62	Miscellaneous Current and Accrued Assets (174)		8,403	115
63	Derivative Instrument Assets (175)		5,210,365	2,214,914
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)		142,223,132	155,918,714
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		2,582,350	3,439,275
70	Extraordinary Property Losses (182.1)	230	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	38,211,758	49,238,541
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)		-12,671	-6,580
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	625,378	1,187,135
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)		3,745,436	2,693,812
82	Accumulated Deferred Income Taxes (190)	234	54,551,854	38,913,316
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		99,704,105	95,465,499
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,227,877,546	1,089,411,298

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Rresubmission	/ /	end of 2007/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	149,248,945	147,608,850
3	Preferred Stock Issued (204)	250-251	15,500,000	15,500,000
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	105,047,383	97,925,074
7	Other Paid-In Capital (208-211)	253	7,260,820	4,720,351
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)	254	3,422,797	3,422,797
11	Retained Earnings (215, 215.1, 216)	118-119	107,142,538	115,071,401
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	156,189,175	129,933,821
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	1,180,702	-1,066,925
16	Total Proprietary Capital (lines 2 through 15)		538,146,766	506,269,775
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	331,290,000	241,320,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	6,985,712	9,314,284
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	70,950
24	Total Long-Term Debt (lines 18 through 23)		338,275,712	250,563,334
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)		763,829	786,829
29	Accumulated Provision for Pensions and Benefits (228.3)		86,674,951	91,182,898
30	Accumulated Miscellaneous Operating Provisions (228.4)		1,364,150	828,810
31	Accumulated Provision for Rate Refunds (229)		805,000	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)		2,447,170	1,334,977
35	Total Other Noncurrent Liabilities (lines 26 through 34)		92,055,100	94,133,514
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	38,900,000
38	Accounts Payable (232)		73,577,723	32,348,050
39	Notes Payable to Associated Companies (233)		0	953
40	Accounts Payable to Associated Companies (234)		2,676,086	919,256
41	Customer Deposits (235)		770,506	804,366
42	Taxes Accrued (236)	262-263	11,770,897	13,947,394
43	Interest Accrued (237)		3,819,213	2,499,207
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 Corporation	(1) [X] An Original (2) [ ] A Rresubmission	/ /	end of 2007/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)		917,239	881,770
48	Miscellaneous Current and Accrued Liabilities (242)		771,378	1,305,116
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		5,077,975	2,011,377
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)		99,381,017	93,617,489
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	16,761,505	8,180,661
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	171,439	13,203,215
60	Other Regulatory Liabilities (254)	278	17,235,022	5,378,955
61	Unamortized Gain on Reaquired Debt (257)		89	207
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		123,057,760	116,055,244
64	Accum. Deferred Income Taxes-Other (283)		2,793,136	2,008,904
65	Total Deferred Credits (lines 56 through 64)		160,018,951	144,827,186
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,227,877,546	1,089,411,298

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

STATEMENT OF INCOME

Quarterly
1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
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 (k) the quarter to date amounts for other utility function for the prior year quarter.
4. 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.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

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	309,903,774	296,012,118		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	209,718,390	189,565,134		
5	Maintenance Expenses (402)	320-323	25,602,021	25,947,301		
6	Depreciation Expense (403)	336-337	24,289,967	23,586,833		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	7,566	7,566		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	458,713	662,523		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	93,287	93,287		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)					
13	(Less) Regulatory Credits (407.4)		101,239	98,302		
14	Taxes Other Than Income Taxes (408.1)	262-263	9,411,607	9,586,604		
15	Income Taxes - Federal (409.1)	262-263	8,105,663	12,312,993		
16	- Other (409.1)	262-263	-281,547	1,961,647		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	16,209,282	12,099,530		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	12,741,922	12,591,366		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,168,484	-1,145,445		
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)		129,650	235,495		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		88,097	85,159		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		279,561,751	261,837,969		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		30,342,023	34,174,149		

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
309,903,774	296,012,118					2
						3
209,718,390	189,565,134					4
25,602,021	25,947,301					5
24,289,967	23,586,833					6
7,566	7,566					7
458,713	662,523					8
93,287	93,287					9
						10
						11
						12
101,239	98,302					13
9,411,607	9,586,604					14
8,105,663	12,312,993					15
-281,547	1,961,647					16
16,209,282	12,099,530					17
12,741,922	12,591,366					18
-1,168,484	-1,145,445					19
						20
						21
129,650	235,495					22
						23
88,097	85,159					24
279,561,751	261,837,969					25
30,342,023	34,174,149					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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)		30,342,023	34,174,149		
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)		7,202,739	6,858,129		
34	(Less) Expenses of Nonutility Operations (417.1)		6,186,959	5,667,471		
35	Nonoperating Rental Income (418)		41,957	42,805		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	33,211,381	27,940,715		
37	Interest and Dividend Income (419)		10,504,055	10,072,783		
38	Allowance for Other Funds Used During Construction (419.1)		-18,594	749,441		
39	Miscellaneous Nonoperating Income (421)		33,479,141	19,373,110		
40	Gain on Disposition of Property (421.1)		16,306	13,057		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		78,250,026	59,382,569		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		20,090			
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	557,643	244,566		
46	Life Insurance (426.2)		-472,639	-897,469		
47	Penalties (426.3)		365			
48	Exp. for Certain Civic, Political & Related Activities (426.4)		216,448	93,397		
49	Other Deductions (426.5)		33,267,472	23,112,783		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		33,589,379	22,553,277		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,850	2,004		
53	Income Taxes-Federal (409.2)	262-263	2,106,068	2,505,715		
54	Income Taxes-Other (409.2)	262-263	-2,758,318	-805,919		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	2,400,160	427,221		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,804,978	2,914,299		
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)		-55,891	-785,951		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		44,716,538	37,615,243		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		16,933,088	15,411,893		
63	Amort. of Debt Disc. and Expense (428)		705,244	614,520		
64	Amortization of Loss on Reaquired Debt (428.1)		327,174	301,355		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		118	118		
67	Interest on Debt to Assoc. Companies (430)	340	1,590,735	1,456,307		
68	Other Interest Expense (431)	340	3,817,390	3,096,321		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,275,656	202,638		
70	Net Interest Charges (Total of lines 62 thru 69)		21,097,857	20,677,640		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		53,960,704	51,111,752		
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)		53,960,704	51,111,752		

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/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		114,887,748	119,567,564
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	FIN 48 Cumulative Effect		-118,576	
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-118,576	
16	Balance Transferred from Income (Account 433 less Account 418.1)		20,749,323	23,171,037
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess hydro licensing amortization		13,619	(6,867)
19	Storm reserve required by First Mortgage Bond Indenture			
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		13,619	(6,867)
23	Dividends Declared-Preferred Stock (Account 437)			
24	$3.60 Preferred $216,000		-216,000	(216,000)
25	$4.40 Preferred $110,000		-110,000	(110,000)
26	$4.65 Preferred $139,500		-139,500	(139,500)
27	$6.75 Preferred $270,000		-270,000	(270,000)
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-735,500	(735,500)
30	Dividends Declared-Common Stock (Account 438)			
31	2007: $1.17 per share; 2006 $1.15 per share		-34,780,138	(33,885,607)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-34,780,138	(33,885,607)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		6,956,028	6,777,121
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		106,972,504	114,887,748
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39	Amortization reserve, federal (Account 215.1)		170,034	183,653
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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)		170,034	183,653
	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)		170,034	183,653
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		107,142,538	115,071,401
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		129,933,821	108,770,227
50	Equity in Earnings for Year (Credit) (Account 418.1)		33,211,382	27,940,715
51	(Less) Dividends Received (Debit)		6,956,028	6,777,121
52				
53	Balance-End of Year (Total lines 49 thru 52)		156,189,175	129,933,821

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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)	53,960,704	51,111,752
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	24,822,475	23,953,377
5	Amortization of intangible plant	458,713	662,523
6	Amortization of plant acquisition adjustments and deferred costs	93,287	93,287
7			
8	Deferred Income Taxes (Net)	-7,851,790	-3,848,844
9	Investment Tax Credit Adjustment (Net)	8,580,844	-1,146,118
10	Net (Increase) Decrease in Receivables	45,245,512	-15,265,863
11	Net (Increase) Decrease in Inventory	-2,704,460	-4,196,242
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	44,663,528	-12,337,167
14	Net (Increase) Decrease in Other Regulatory Assets	11,026,783	-30,882,485
15	Net Increase (Decrease) in Other Regulatory Liabilities	11,856,067	-3,663,039
16	(Less) Allowance for Other Funds Used During Construction	-18,594	749,441
17	(Less) Undistributed Earnings from Subsidiary Companies	26,255,353	21,163,594
18	Other: (Increase) decrease in noncurrent assets and deferred debits	-2,984,392	14,306,251
19	Other: Increase(decrease) in noncurrent liabilities & deferred credits	-12,910,306	23,337,933
20	Other: (Increase) decrease in other current assets	-11,305,318	5,068,435
21	Other: Losses on investments in noncurrent assets	353,301	728,319
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	137,068,189	26,009,084
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-125,529,395	-31,087,220
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-736,921	-125,627
30	(Less) Allowance for Other Funds Used During Construction	18,594	-749,441
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-126,284,910	-30,463,406
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	-18,628,715	11,977,251
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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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:(Increase) Decrease in funds on deposit with trustee	222,403	-271,616
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-144,691,222	-18,757,771
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	205,000,000	
62	Preferred Stock		
63	Common Stock	11,302,873	4,777,398
64	Other: Payments for debt issuance expenses	856,925	85,719
65			
66	Net Increase in Short-Term Debt (c)		22,900,000
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	217,159,798	27,763,117
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-117,358,572	-2,328,572
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)	-38,900,000	
79			
80	Dividends on Preferred Stock	-735,500	-735,500
81	Dividends on Common Stock	-34,780,138	-33,885,607
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	25,385,588	-9,186,562
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	17,762,555	-1,935,249
87			
88	Cash and Cash Equivalents at Beginning of Period	9,541,573	11,476,822
89			
90	Cash and Cash Equivalents at End of period	27,304,128	9,541,573

Name of Respondent Otter Tail Corporation	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2007/Q4

FOOTNOTE DATA

Schedule Page: 120 Line No.: 5 Column: a
Amortization of intangible plant.

Schedule Page: 120 Line No.: 6 Column: a
Amortization of plant acquisition adjustments and deferred costs.

Schedule Page: 120 Line No.: 18 Column: a
Changes in miscellaneous deferred debits.

Schedule Page: 120 Line No.: 19 Column: a
Includes changes in: other investments, other special funds, clearing accounts, miscellaneous deferred 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.: 53 Column: a
Change in special funds on deposit with fiscal agent.

Schedule Page: 120 Line No.: 64 Column: a
Change in unamortized debt expense.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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.

	2007	2006
Cash Equivalents	$ 22,435,436	$ 7,813,219

Reconciliation	2007	2006
Cash – Account 131 (Line 35, Page 110)	$ 4,846,287	$ 1,705,474
Working Fund – Account 135 (Line 37, Page 110)	22,405	22,880
Cash Equivalent – Account 136 (Above)	22,435,436	7,813,219
	$ 27,304,128	$ 9,541,573
Supplemental Disclosure of Cash Flow Information:		
Cash Paid During the year for:		
Interest (Net of Amount Capitalized)	$ 17,274,155	$ 18,178,957
Income Taxes	$ 8,594,658	$ 19,305,230

Otter Tail Corporation
Notes to Comparative Financial Statements
For the years ended December 31, 2007 and 2006

1. Summary of Significant Accounting Policies

Principles of Consolidation
The Company has several subsidiaries. The net investment in such subsidiaries is included in Other Property and Investments and the results of subsidiaries’ operations are included in Other Income and Deductions. If Generally Accepted Accounting Principles (GAAP) were followed, the respective assets and liabilities of these subsidiaries would be included in the accompanying financial statements.

Regulation and Statement of Financial Accounting Standards No. 71
As a regulated entity, the Company accounts for the financial effects of regulation in accordance with SFAS No. 71. This statement 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, the Company defers utility debt redemption premiums and amortizes such costs over the original life of the reacquired bonds. See note 3 for further discussion.

The Company’s regulated electric utility business 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). These accounting policies differ in some respects from those used by the Company’s nonelectric businesses.

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. This report differs from GAAP due to FERC requiring the presentation of subsidiaries on the equity method of accounting, which differs from Statement of Financial Accounting Standards No. 94, "Consolidation of All Majority-Owned Subsidiaries" (SFAS No. 94). SFAS No. 94 requires that all majority-owned subsidiaries be consolidated. The Company has several subsidiaries and the net investment in such subsidiaries is included in Other Property and Investments and the results for these subsidiaries' operations are included in Other Income and Deductions. In addition, the associated Goodwill and certain intangible assets related to these subsidiaries are excluded for FERC regulatory reporting as compared to GAAP requirements which would include the amounts. The other 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 tax asset or liability.

See note 13 for details.

Plant, Retirements and Depreciation

Utility plant is stated at original cost. The cost of additions includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction. The amount of interest capitalized on electric utility plant was $2,257,000 in 2007 and $952,000 in 2006. 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 2.78% in 2007and 2.82% in 2006. 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 comparative balance sheets include the Company'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, 2007 and 2006 comparative balance sheets:

(in thousands)	Big Stone Plant	Coyote Station
December 31, 2007		
Electric Plant in Service	$ 136,493	$ 147,724
Accumulated Depreciation	(72,342)	(83,417)
Net Plant	$ 64,151	$ 64,307
December 31, 2006		
Electric Plant in Service	$ 124,965	$ 147,319
Accumulated Depreciation	(75,872)	(80,336)
Net Plant	$ 49,093	$ 66,983

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

Recoverability of Long-Lived Assets

The Company reviews its long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. The Company determines potential impairment by comparing the carrying value 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 values, the Company would determine whether an impairment loss should be recognized. An impairment loss would be quantified by comparing the amount by which the carrying value 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. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect in the periods when the temporary differences reverse. The Company amortizes tax credits over the estimated lives of related property. Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109,* was issued in June 2006. FIN No. 48 clarifies the accounting for uncertain tax positions in accordance with SFAS No. 109, *Accounting for Income Taxes*. The Company adopted FIN No. 48 on January 1, 2007 and has recognized, in its comparative 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 December 31, 2007. The term "more-likely-than-not" means a likelihood of more than 50%.

Revenue Recognition

In the case of derivative instruments, such as the electric utility's forward energy contracts, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended and interpreted. 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.

Electric customers' meters are read 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.

Revenues on wholesale electricity sales from Company-owned generating units are recognized when energy is delivered.

The Company'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 the Company's comparative statement of income. Under SFAS No. 133 as amended and interpreted, the Company'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. The Company 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

The Company 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, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, unbilled electric revenues, valuations of forward energy contracts, residual load adjustments related to purchase and sales transactions processed through the Midwest Independent Transmission System Operator (MISO) that are pending settlement 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

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

Investments

At December 31, 2007 and 2006 the Company had investments of $1,837,000 and $2,216,000, respectively, in limited partnerships that invest in tax-credit qualifying affordable housing projects. These investments provided the Company with tax credits of $285,000 in 2007 and $839,000 in 2006. The balance of investments at December 31, 2007 consists of $30,000 in additional investments accounted for under the equity method, $500,000 of additional investments accounted under the cost method and $655,000 related to participation in economic development loan pools accounted for under the cost method. The balance of investments at December 31, 2006 consists of $29,000 in additional investments accounted for under the equity method, $500,000 of additional investments accounted for under the cost method and $569,000 related to participation in economic development loan pools accounted for under the cost method. (See further discussion under note 11.)

The Company's marketable securities classified as available-for-sale are held for insurance purposes and are reflected at their market values on December 31, 2007. See further discussion under note 11.

Inventories

The Electric operation inventories are reported at average cost. Inventories consist of plant materials, fuel, and operating supplies.

New Accounting Standards

SFAS No. 123(R) (revised 2004), ***Share-Based Payment,*** issued in December 2004, is a revision of SFAS No. 123, *Accounting for Stock-based Compensation,* and supersedes Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees.* Beginning in January 2006, the Company adopted SFAS No. 123(R) on a modified prospective basis. The Company is required to record stock-based compensation as an expense on its income statement over the period earned based on the fair value of the stock or options awarded on their grant date. The application of SFAS No. 123(R) reporting requirements resulted in recording incremental after-tax compensation expense in 2006 as follows:

- $163,000, net-of-tax, in 2006 for non-vested stock options that were outstanding on December 31, 2005.
- $235,000 in 2006 for the 15% discount offered under the Company's Employee Stock Purchase Plan.

For years prior to 2006, the Company reported its stock-based compensation under the requirements of APB No. 25 and furnished related pro forma footnote information required under SFAS No. 123. See note 7 for additional discussion.

In November 2005, the FASB issued FASB Staff Position (FSP) No. FAS 123(R)-3, *Transition Election Related to Accounting for Tax Effects of Share-Based Payment Awards.* The Company elected to adopt the alternative transition method provided in FSP No. FAS 123(R)-3 for calculating the tax effects of stock-based compensation. The alternative transition method includes simplified methods to determine the beginning balance of the Additional Paid-In Capital (APIC) pool related to the tax effects of stock-based compensation, and to determine the subsequent impact on the APIC pool and the statement of cash flows of the tax effects of stock-based awards that were fully vested and outstanding upon the adoption of SFAS No. 123(R).

FIN No. 48, ***Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109,*** was issued by the FASB in June 2006. FIN No. 48 clarifies the accounting for uncertain tax positions in accordance with SFAS No. 109, *Accounting for Income Taxes*. The Company adopted FIN No. 48 on January 1, 2007 and has recognized, in its comparative 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 December 31, 2007. The term "more-likely-than-not" means a likelihood of more than 50%. FIN No. 48 also provides guidance on new disclosure requirements, reporting and accrual of interest and penalties, accounting in interim periods and transition. Only tax positions that meet the "more-likely-than-not" threshold on the reporting date may be recognized. See note 14 for additional discussion.

SFAS No. 157, ***Fair Value Measurements,*** was issued by the FASB in September 2006. SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 will be effective for fiscal years beginning after November 15, 2007. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements where fair value is the relevant measurement attribute. Accordingly, this statement does not require any new fair value measurements. Other than additional footnote disclosures related to the use of fair value measurements in the areas of derivatives, goodwill and asset impairment evaluations and financial instruments, the Company does not expect the adoption of SFAS No. 157 to have a significant impact on its comparative balance sheet, income statement or statement of cash flows.

SFAS No. 158, ***Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans,*** was issued by the FASB in September 2006 and became effective for the Company in 2006. SFAS No. 158 requires employers to recognize, on a prospective basis, the funded status of their defined benefit pension and other postretirement plans on their comparative balance sheet and to recognize, as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits and transition assets or obligations that have not been recognized as components of net periodic benefit cost. SFAS No. 158 also requires additional disclosures in the notes to financial statements. SFAS No. 158 did not change the amount of net periodic benefit expense recognized in an entity's income statement. The Company determined the balance of unrecognized net actuarial losses, prior service costs and the SFAS No. 106

transition obligation related to regulated utility activities would be subject to recovery through rates as those balances are amortized to expense and the related benefits are earned. Therefore, the Company charged those unrecognized amounts to regulatory asset accounts under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, rather than to Accumulated Other Comprehensive Loss in equity as prescribed by SFAS No. 158. Application of this standard had the following effects on the Company's December 31, 2006 comparative balance sheet:

(in thousands)	2006
Decrease in Executive Survivor and Supplemental Retirement Plan Intangible Asset	$ (767)
Increase in Regulatory Assets (for the unrecognized portions of net actuarial losses, prior service costs and transition obligations that are subject to recovery through electric rates)	36,736
Increase in Pension Benefit and Other Postretirement Liability	(34,714)
Increase in Deferred Tax Liability	(502)
Decrease in Accumulated Other Comprehensive Loss (for the unrecognized portions of net actuarial losses, prior service costs and transition obligations that are not subject to recovery through electric rates) (increase to equity)	(753)

The adoption of this standard did not affect compliance with debt covenants maintained in the Company's financing agreements.

SFAS No. 159, ***The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115,*** was issued by the FASB in February 2007. SFAS No. 159 provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses in earnings at each subsequent reporting date on items for which the fair value option has been elected. This statement also establishes presentation and disclosure requirements to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. As of December 31, 2007 the Company had not opted, nor does it currently plan to opt, to apply fair value accounting to any financial instruments or other items that it is not currently required to account for at fair value.

SFAS No. 141 (revised 2007), Businesses Combinations (SFAS No. 141(R)), was issued by the FASB in December 2007. SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations,* and will apply prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008—January 1, 2009 for the Company. SFAS No. 141(R) applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree). In addition to replacing the term "purchase method of accounting" with "acquisition method of accounting," SFAS No. 141(R) requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance will replace SFAS No. 141's cost-allocation process, which requires the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. SFAS No. 141's guidance results in not recognizing some assets and liabilities at the acquisition date, and it also results in measuring some assets and liabilities at amounts other than their fair values at the acquisition date. For example, SFAS No. 141 requires the acquirer to include the costs incurred to effect an acquisition (acquisition-related costs) in the cost of the acquisition that is allocated to the assets acquired and the liabilities assumed. SFAS No. 141(R) requires those costs to be expensed as incurred. In addition, under SFAS No. 141, restructuring costs that the acquirer expects but is not obligated to incur are recognized as if they were a liability assumed at the acquisition date. SFAS No. 141(R) requires the acquirer to recognize those costs separately from the business combination.

2. Rate and Regulatory Matters

Minnesota

General Rate Case--The electric utility filed a general rate case in Minnesota on October 1, 2007 requesting an interim rate increase of 5.41% effective November 30, 2007 and a final total rate increase of approximately 11%. However, the electric utility is proposing to share asset-based wholesale margins through the FCA, so the final overall customer impact would be an increase of approximately 6.7%. The electric utility's interim rate request was approved and will remain in effect for all Minnesota customers until the Minnesota Public Utilities Commission (MPUC) makes a final determination on the final request, which is expected by August 1, 2008. If the MPUC approves final rates that are lower than interim rates, the electric utility will refund Minnesota customers the difference with interest.

Capacity Expansion 2020 (CapX 2020) Mega Certificate of Need--On August 16, 2007 the eleven CapX 2020 utilities asked the MPUC to determine the need for three 345-kilovolt transmission lines. These lines would help ensure continued reliable electricity service in Minnesota and the surrounding region by upgrading and expanding the high-voltage transmission network and providing capacity for more wind energy resources to be developed in southern and western Minnesota, eastern North Dakota and South Dakota. The proposed lines would span more than 600 miles and represent one of the largest single transmission initiatives in the region in several years. The MPUC is expected to decide if the lines are needed by early 2009. The MPUC would determine routes for the new lines in separate proceedings. Portions of the lines 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 complete (expected in 2009 or 2010), construction will begin. The lines would be expected to be completed three or four years later. Great River Energy and Xcel Energy are leading the project, and Otter Tail Power Company and eight other utilities are involved in permitting, building and financing. The electric utility's 2008 – 2012 capital budgets include $67 million for CapX 2020 expenditures.

Renewable Energy Standards, Conservation and Renewable Resource Riders--In February 2007, the Minnesota legislature passed a renewable energy standard requiring the electric utility 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. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards.

Under the Next Generation Energy Act passed by the Minnesota legislature in May 2007, an automatic adjustment mechanism was established to allow Minnesota electric utilities to recover charges incurred to satisfy the requirements of the renewable energy standards. The MPUC is now authorized to approve a rate schedule rider to recover the costs of qualifying renewable energy projects to 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 in an integrated resource plan or certificate of need proceeding before the MPUC. Renewable resource costs eligible for recovery may include return or investment, depreciation, operation and maintenance costs, taxes, renewable energy delivery costs and other related expenses. The electric utility has requested approval of a renewable resource rider that would allow recovery of eligible and prudently incurred costs for its qualifying renewable energy project investments. The proposed rider would cover the Minnesota jurisdictional portion of such eligible costs. The electric utility expects to receive MPUC approval of its proposed rider in 2008.

In addition, the Minnesota Public Utilities Act provides a similar mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new electric transmission facilities. The MPUC may approve a tariff to recover the Minnesota jurisdictional costs of new transmission facilities that have been previously approved by the MPUC in a certificate of need proceeding or certified by the MPUC as a Minnesota priority transmission project. Such transmission cost recovery riders would allow a return on investments at the level approved in the utility's last general rate case. The electric utility is also preparing to file a proposed rider to recover its share of costs of transmission infrastructure upgrades projects. The electric utility currently expects to file its transmission cost recovery tariff and receive MPUC approval during 2008.

Recovery of MISO Costs--In December 2005, the MPUC issued an order denying the electric utility's request to allow recovery of certain MISO-related costs through the FCA in Minnesota retail rates and requiring a refund of amounts previously collected pursuant to an interim order issued in April 2005. The electric utility recorded a $1.9 million reduction in revenue and a refund payable in December 2005 to reflect the refund obligation. On February 9, 2006 the MPUC decided to reconsider its December 2005 order. The MPUC's final order was issued on February 24, 2006 requiring jurisdictional investor-owned utilities in the state to participate with the Minnesota Department of Commerce (MNDOC) and other parties in a proceeding that would evaluate suitability of recovery of certain MISO Day 2 energy market costs through the FCA. The February 24, 2006 order eliminated the refund provision from the December 2005 order and allowed that any MISO-related costs not recovered through the FCA may be deferred for a period of 36 months, with possible recovery through base rates in the utility's next general rate case. As a result, the electric utility recognized $1.9 million in revenue and reversed the refund payable in February 2006. The Minnesota utilities and other parties submitted a final report to the MPUC in July 2006.

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. That 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. According to the order, a utility may, in its next rate case, seek to recover schedule 16 and 17 costs at an appropriate level of base rate recovery, provided it shows those costs were prudently incurred, reasonable, resulted in benefits justifying recovery and not already recovered through other rates. Also, a utility may seek to recover schedule 16 and 17 costs and associated amortizations through interim rates pending the resolution of a general rate case, subject to final MPUC approval. Pursuant to this December 20, 2006 order, the electric utility 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. As of December 31, 2007 the electric utility had refunded $407,000 of the $446,000 and deferred $855,000 in MISO schedule 16 and 17 costs. The electric utility has also requested recovery of the deferred costs and recovery of the ongoing costs in its pending general rate case. The Residential and Small Business Utilities Division of the Office of the Attorney General (RUD-OAG) has appealed the December 20, 2006 order to the Minnesota Court of Appeals.

Minnesota Annual Automatic Adjustment Report on Energy Costs (AAA Report)--The MNDOC and the electric utility 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 the sale of Financial Transmission Rights (FTRs) not needed for retail load. For the period July 1, 2005 through June 30, 2007 the electric utility 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. The electric utility 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. The electric utility also agreed to modifications to the MISO Day 2 cost allocations that were resolved in the MPUC's December 20, 2006 order. The electric utility agreed to make some of those modifications retroactive back to January 1, 2007. The MPUC accepted the electric utility's refund offer and modifications and closed this docket on February 6, 2008. In December 2007, the electric utility 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.

Claims of Improper Regulatory Filings--In September 2004, the Company provided a letter to the MPUC summarizing issues and conclusions of an internal investigation completed by the Company related to claims of allegedly improper regulatory filings brought to the attention of the Company by certain individuals. On November 30, 2004 the electric utility filed a report with the MPUC responding to these claims. In 2005, the Energy Division of the MNDOC, the RUD-OAG and the claimants filed comments in response to the report, to which the electric utility filed reply comments. A hearing before the MPUC was held on February 28, 2006. As a result of the hearing, the electric utility agreed that within 90 days it would file a revised Regulatory Compliance Plan, an updated Corporate Cost Allocation Manual and documentation of the definitions of its chart of accounts. The electric utility filed these documents with the MPUC in the second quarter of 2006. The electric utility received comments on its filings from the MNDOC and the claimants and filed reply comments in August 2006.

The MNDOC recommended accepting the revised Regulatory Compliance Plan and the chart of accounts definition. The electric utility filed supplemental comments related to its Corporate Allocation Manual in November 2006. The electric utility also agreed to file a general rate case in Minnesota on or before October 1, 2007. At a MPUC hearing on January 25, 2007 all remaining open issues were resolved. The MPUC accepted the electric utility's compliance filing with minor changes, agreed to allow the electric utility to calculate corporate cost allocations as proposed, determined not to conduct any further review at this time and required the electric utility to include all of the Company's short-term debt in its calculations of allowance for funds used during construction. The electric utility agreed to provide the MPUC the results of the current FERC operational audit when available, compare the corporate allocation method to a commonly accepted methodology in the next rate case, and provide the results of the Company's investigation relating to a 2007 hotline complaint. The Company recorded a noncash charge to Other Income and Deductions of $3.3 million in 2006 related to the disallowance of a portion of capitalized costs of funds used during construction from the electric utility's rate base. On December 12, 2007 the MPUC issued its order closing the investigation subject to the Company's continuing responsibility to file the report on its FERC operational audit as soon as it becomes available and subject to any further development of the record required in the electric utility's pending general rate case.

North Dakota

In February 2005, the electric utility filed a petition with the North Dakota Public Service Commission (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 the electric utility and an intervener representing several large industrial customers in North Dakota. When the MISO Day 2 energy market began in April 2005, the characterization of some of the electric utility's energy costs changed, though the essential nature of those costs did not. Fuel and purchased energy costs incurred to serve retail customers are recoverable through the FCA in North Dakota. Under the approved settlement agreement, the electric utility will refund to North Dakota customers the schedule 16 and 17 costs collected through the FCA since April 2005. The electric utility can defer recognition of these costs and request recovery of them in its next general rate case. Purchase Power – Electric System Use expense was reduced and an offsetting regulatory asset was established for the amount of the refund. The refund amount of $493,000 was credited to North Dakota customers through the FCA beginning in October 2007. Also as part of the settlement, the electric utility agreed to file a general rate case in North Dakota between November 1 and December 31, 2008. As of December 31, 2007 the electric utility had deferred $576,000 in MISO schedule 16 and 17 costs in North Dakota pending the allowed recovery of those costs in its next rate case.

Federal

Revenue Sufficiency Guarantee (RSG) Charges--On April 25, 2006 the FERC issued an order requiring MISO to refund to customers, with interest, amounts related to real-time RSG charges that were not allocated to day-ahead virtual supply offers in accordance with MISO's Transmission and Energy Markets Tariff (TEMT) going back to the commencement of MISO Day 2 markets in April 2005. On May 17, 2006 the FERC issued a Notice of Extension of Time, permitting MISO to delay compliance with the directives contained in its April 2006 order, including the requirement to refund to customers the amounts due, with interest, from April 1, 2005 and the requirement to submit a compliance filing. The Notice stated that the order on rehearing would provide the appropriate guidance regarding the timing of compliance filing. On October 26, 2006 the FERC issued an order on rehearing of the April 25, 2006 order, stating it would not require refunds related to real-time RSG charges that had not been allocated to day-ahead virtual supply offers in accordance with MISO's TEMT going back to the commencement of the MISO Day 2 market in April 2005. However, the FERC ordered prospective allocation of RSG charges to virtual transactions consistent with the TEMT to prevent future inequity and directed MISO to propose a charge that assesses RSG costs to virtual supply offers based on the RSG costs that virtual supply offers cause within 60 days of the October 26, 2006 order. On December 27, 2006 the FERC issued an order granting rehearing of the October 26, 2006 order.

On March 15, 2007 the FERC issued an order denying requests for rehearing of the RSG rehearing order dated October 27, 2006. In the March 15, 2007 order on rehearing, the FERC stated that its findings in the April 25, 2006 RSG order that virtual offers should share in the allocation of RSG costs, per the terms of the currently effective tariff, served as notice to market participants that virtual offers, for those market participants withdrawing energy, were liable for RSG charges. FERC clarified that the RSG rehearing order's waiver of refunds applies to the period before that order, from market start-up in April 2005 until April 24, 2006. After that date, virtual supply offers are liable for RSG costs and therefore, to the extent virtual supply offers were not assessed RSG costs, refunds are due for the period starting April 25, 2006.

On November 5, 2007 the FERC issued two orders related to the RSG proceeding. In the first order, the FERC accepted the MISO's April 17, 2007 RSG compliance filing to comply with the FERC's March 15, 2007 RSG order. The compliance reinserted language requiring the actual withdrawal of energy by market participants, restored the MISO's original TEMT language allocating RSG costs to virtual transactions, revised the effective date for allocation to imports, provided an explanation of its efforts to reflect partial-hour revenue determinations in its software development, and revised several definitions. The second related RSG order issued by FERC on November 5, 2007 was its order on rehearing on its April 25, 2006 order in which it rejected the MISO's proposal to remove references to virtual supply from the TEMT provisions related to calculating RSG charges (FERC Docket Nos. ER04-691-084 and ER04-691-086). In this order, the FERC denied the requests for rehearing of the RSG second rehearing order (the electric utility was one of the parties that sought rehearing) and FERC denied all requests for rehearing of the RSG compliance order.

In the RSG compliance order, the FERC rejected the MISO's proposal to allocate costs based on net virtual offers, i.e., virtual offers minus virtual bids, and clarified that the currently effective tariff, which allocates RSG costs to virtual supply offers, remains in effect. In the RSG second rehearing order, the FERC clarified that for those market participants withdrawing energy, to the extent virtual supply offers were not assessed RSG costs, refunds were due for the period starting April 25, 2006.

The electric utility recorded a $1.7 million ($1.0 million net-of-tax) charge to earnings in the first quarter of 2007 based on an internal estimate of the net impact of MISO reallocating RSG charges in response to the FERC order on rehearing. In May 2007, MISO informed affected market participants of the impact of reallocating charges based on its interpretation of the FERC order on rehearing. Based on MISO's interpretation of the order on rehearing, the electric utility estimated the reallocation of charges would not have a significant impact on earnings previously recognized by the electric utility. Accordingly, the electric utility revised its first quarter estimated charge of $1.7 million ($1.0 million net-of-tax) to zero in the second quarter of 2007. The electric utility is awaiting FERC's response to MISO's December 5, 2007 RSG compliance filing and cannot determine what financial impact, if any, the filing will have on the Company's comparative results of operations. However, MISO has stated there will be no additional resettlements related to this matter.

Transmission Practices Audit--The Division of Operation Audits of the FERC Office of Market Oversight and Investigations (OMOI) commenced an audit of the electric utility's transmission practices in 2005. The purpose of the audit is to determine whether and how the electric utility's transmission practices are in compliance with the FERC's applicable rules and regulations and tariff requirements and whether and how the implementation of the electric utility's waivers from the requirements of Order No. 889 and Order No. 2004 restricts access to transmission information that would benefit the electric utility's off-system sales. The Division of Operation Audits of the OMOI has not issued an audit report. The Company cannot predict if the results of the audit will have any impact on the Company's comparative financial statements.

Big Stone II Project

On June 30, 2005 the electric utility 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. The three primary agreements are the Participation Agreement, the Operation and Maintenance Agreement and the Joint Facilities Agreement. Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency are parties to all three agreements. In September 2007, Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. The five remaining project participants decided to downsize the proposed plant's nominal generating capacity from 630 megawatts to between 500 and 580 megawatts. New procedural schedules have been established in the various project-related proceedings, which will take into consideration the optimal plant configuration decided on by the remaining participants. NorthWestern Corporation, one of the co-owners of the existing Big Stone Plant, is an additional party to the Joint Facilities Agreement.

The electric utility and the coalition of six other electric providers filed an application for a Certificate of Need for the Minnesota portion of the Big Stone II transmission line project on October 3, 2005 and filed an application for a Route Permit for the Minnesota portion of the Big Stone II transmission line project with the MPUC on December 9, 2005. Evidentiary hearings were conducted in December 2006 and all parties submitted legal briefs. The Administrative Law Judges (ALJs) on August 15, 2007 recommended approval of the Certificate of Need subject to potential conditions. The electric utility and project participants addressed the ALJs' recommended potential conditions in an August 31, 2007 proposed settlement agreement with the MNDOC that was entered into the record of the Certificate of Need/Route Permit dockets. The MPUC had not acted on the applications or the proposed settlement agreement when Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. On October 19, 2007 the MPUC requested that the ALJs recommence proceedings in the matter and that the remaining project participants file testimony describing and supporting a revised Big Stone II project. The remaining five participants filed testimony on November 13, 2007. On December 3, 2007 the ALJs issued an order refining the scope of the additional proceedings. Evidentiary hearings were held on January 23-25, 2008. The electric utility anticipates the ALJs will issue their report and recommendation in March 2008 and the MPUC will decide the matters in April 2008. The electric utility's integrated resource plan (IRP) includes generation from Big Stone II beginning in 2013 to accommodate load growth and to replace expiring purchased power contracts and older coal-fired base-load generation units scheduled for retirement. In addition to approval of the Certificate of Need/Route Permit applications for the transmission line project, approval of this IRP is pending with the MPUC.

A filing in North Dakota for an advanced determination of prudence of Big Stone II was made by the electric utility in November 2006. Evidentiary hearings were held in June 2007. The NDPSC decision was delayed because of the change in ownership of the project. The administrative law judge in the matter scheduled supplemental hearings in April 2008.

The electric utility and the coalition of six other electric providers filed an Energy Conversion Facility Siting Permit Application for Big Stone II with the South Dakota Public Utilities Commission (SDPUC) on July 21, 2005. The permit was granted by the SDPUC on July 14, 2006 but was appealed by a group of interveners on the basis that carbon dioxide concerns had not been adequately addressed. In February 2007, a South Dakota circuit court judge issued an opinion affirming the decision of the SDPUC to grant the siting permit for Big Stone II. The permit was appealed to the South Dakota Supreme Court. On January 16, 2008 the South Dakota Supreme Court unanimously affirmed the SDPUC's decision to grant Big Stone II project participants a site permit. A permit application for the South Dakota portion of the transmission line for Big Stone II was filed with the SDPUC on January 16, 2006 and was approved by the SDPUC on January 2, 2007.

As of December 31, 2007 the electric utility has capitalized $8.2 million in costs related to the planned construction of Big Stone II. Should approvals of permits not be received on a timely basis, the project could be at risk. If the project is abandoned for permitting or other reasons, these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

3. Regulatory Assets and Liabilities

The following table indicates the amount of regulatory assets and liabilities recorded on the Company's comparative balance sheets:

(in thousands)	December 31, 2007	December 31, 2006
Regulatory Assets:		
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pension and Other Postretirement Benefits	$ 26,933	$ 36,736
Accrued Cost-of-Energy Revenue	19,452	10,735
Deferred Income Taxes	8,733	11,712
Reacquisition Premiums	3,745	2,694
MISO Schedule 16 and 17 Deferred Administrative Costs - MN	855	541
Deferred Marked-to-Market Losses	771	--
MISO Schedule 16 and 17 Deferred Administrative Costs - ND	576	--
Deferred Conservation Program Costs	518	1,036
Accumulated ARO Accretion/Depreciation Adjustment	345	249
Plant Acquisition Costs	107	151
Total Regulatory Assets	$ 62,035	$ 63,854
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs	$ 12,317	$ 13,093
Deferred Income Taxes	4,502	5,228
Deferred Marked-to-Market Gains	271	--
Gain on Sale of Division Office Building	145	151
Total Regulatory Liabilities	$ 17,235	$ 18,472
Net Regulatory Asset Position	$ 44,800	$ 45,382

The regulatory asset related to the unrecognized transition obligation on postretirement medical benefits and prior service costs and actuarial losses on pension and other postretirement benefits represents benefit costs that will be subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs were required to be recognized as components of Accumulated Other Comprehensive Loss in equity under SFAS No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans,* adopted in December 2006, but were determined to be eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates. Accrued Cost-of-Energy Revenue included in Accrued Utility and Cost-of-Energy Revenues will be recovered over the next nine months. The regulatory assets and liabilities related to Deferred Income Taxes result from changes in statutory tax rates accounted for in accordance with SFAS No. 109, *Accounting for Income Taxes*. Reacquisition Premiums included in Unamortized Debt Expense are being recovered from electric utility customers over the remaining original lives of the reacquired debt issues, the longest of which is 24.7 years. MISO Schedule 16 and 17 Deferred Administrative Costs – MN were excluded from recovery through the FCA in Minnesota in a December 2006 order issued by the MPUC. The MPUC ordered the electric utility to refund MISO schedule 16 and 17 charges that had been recovered through the FCA since the inception of MISO Day 2 markets in April 2005, but allowed for deferral and possible recovery of those costs through rates established in the electric utility's Minnesota general rate case filed on October 1, 2007. All deferred marked-to-market losses and gains are related to forward purchases of energy scheduled for delivery in January and February of 2008. MISO Schedule 16 and 17 Deferred Administrative Costs - ND were excluded from recovery through the FCA in North Dakota in an August 2007 order issued by the NDPSC. The NDPSC ordered the electric utility to refund MISO schedule 16 and 17 charges that had been recovered through the FCA since the inception of MISO Day 2 markets in April 2005, but allowed for deferral and possible recovery of those costs through rates established in the electric utility's next general rate case in North Dakota scheduled to be filed in November or December of 2008. Deferred Conservation Program Costs represent mandated conservation expenditures recoverable through retail electric rates over the next 1.5 years. Plant Acquisition Costs will be amortized over the next 2.4 years. The Accumulated Reserve for Estimated Removal Costs is reduced for actual removal costs incurred. The remaining regulatory assets and liabilities are being recovered from, or will be paid to, electric customers over the next 30 years.

If for any reason, the Company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from the comparative balance sheet and included in the comparative statement of income as an extraordinary expense or income item in the period in which the application of SFAS No. 71 ceases.

4. Forward Energy Contracts Classified as Derivatives

Electricity Contracts

All of the electric utility'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. The electric utility'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. The electric utility'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. The electric utility 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.

5. Common Shares and Earnings Per Share

Following is a reconciliation of the Company's common shares outstanding from December 31, 2006 through December 31, 2007:

Common Shares Outstanding, December 31, 2006	29,521,770
Issuances:	
Stock Options Exercised	298,601
Directors' Compensation:	
Restricted Shares	15,200
Unrestricted Shares	885
Vesting of Restricted Stock Units	4,522
Restricted Shares Issued for Employee Compensation	17,300
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(8,409)
Restricted Shares Forfeited	(80)
Common Shares Outstanding, December 31, 2007	29,849,789

Stock Incentive Plan

The 1999 Stock Incentive Plan, as amended (Incentive Plan), provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards, and other stock and stock-based awards. A total of 3,600,000 common shares are authorized for granting stock awards under the Incentive Plan, which terminates on December 13, 2013.

Employee Stock Purchase Plan

The 1999 Employee Stock Purchase Plan (Purchase Plan) allows eligible employees to purchase the Company's common shares at 85% of the market price at the end of each six-month purchase period. The number of common shares authorized to be issued under the Purchase Plan is 900,000, of which 397,156 were still available for purchase as of December 31, 2007. At the discretion of the Company, shares purchased under the Purchase Plan can be either new issue shares or shares purchased in the open market. To provide shares for the Purchase Plan, 52,558 common shares were purchased in the open market in 2007, 53,258 common shares were purchased in the open market in 2006. The shares to be purchased by employees participating in the Purchase Plan are not considered dilutive for the purpose of calculating diluted earnings per share during the investment period.

Dividend Reinvestment and Share Purchase Plan

On August 30, 1996 the Company filed a shelf registration statement with the Securities and Exchange Commission (SEC) for the issuance of up to 2,000,000 common shares pursuant to the Company's Automatic Dividend Reinvestment and Share Purchase Plan (the Plan), which permits shares purchased by shareholders or customers who participate in the Plan to be either new issue common shares or common shares purchased in the open market. From June 1999 through December 2003, common shares needed for the Plan were purchased in the open market. From January through October 2004 new shares were issued for this Plan. Starting in November 2004 the Company began purchasing common shares in the open market. Through December 31, 2007, 944,507 common shares had been issued to meet the requirements of the Plan.

Shareholder Rights Plan

On January 27, 1997 the Company's Board of Directors declared a dividend of one preferred share purchase right (Right) for each outstanding common share held of record as of February 15, 1997. One Right was also issued with respect to each common share issued after February 15, 1997. The Rights expired pursuant to their terms on January 27, 2007.

Earnings Per Share

Basic earnings per common share are calculated by dividing earnings available for common shares by the weighted average number of common shares outstanding during the period. Diluted earnings per common share are calculated by adjusting outstanding shares, assuming conversion of all potentially dilutive stock options. Stock options with exercise prices greater than the market price are excluded from the calculation of diluted earnings per common share. Nonvested restricted shares granted to the Company’s directors and employees are considered dilutive for the purpose of calculating diluted earnings per share but are considered contingently returnable and not outstanding for the purpose of calculating basic earnings per share. Underlying shares related to nonvested restricted stock units granted to employees are considered dilutive for the purpose of calculating diluted earnings per share. Shares expected to be awarded for stock performance awards granted to executive officers are considered dilutive for the purpose of calculating diluted earnings per share.

Excluded from the calculation of diluted earnings per share are the following outstanding stock options which had exercise prices greater than the average market price for the years ended December 31, 2007 and 2006:

Year	Options Outstanding	Range of Exercise Prices
2007	--	NA
2006	210,250	$29.74 - $31.34

6. Share-Based Payments

On January 1, 2006 the Company adopted the accounting provisions of SFAS No. 123(R) (revised 2004), *Share-Based Payment,* on a modified prospective basis. SFAS No. 123(R) is a revision of SFAS No. 123, *Accounting for Stock-based Compensation,* and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees.* Under SFAS No. 123(R), the Company records stock-based compensation as an expense on its income statement over the period earned based on the estimated fair value of the stock or options awarded on their grant date. The Company elected the modified prospective method of adopting SFAS No. 123(R), under which prior periods are not retroactively revised. The valuation provisions of SFAS No. 123(R) apply to awards granted after the effective date. Estimated stock-based compensation expense for awards granted prior to the effective date but that remain nonvested on the effective date will be recognized over the remaining service period using the compensation cost estimated for the SFAS No. 123 pro forma disclosures. Additionally, the adoption of SFAS No. 123(R) resulted in the reclassification of $798,000 in credits related to outstanding restricted share-based compensation from equity on the Company’s comparative balance sheet to a liability on January 1, 2006 because of income tax withholding provisions in the share-based award agreements. The adoption of SFAS 123(R) also resulted in the elimination of Unearned Compensation from the equity section of the Company’s comparative balance sheet on January 1, 2006 by netting the account balance of $1,720,000 against Premium on Common Shares.

As of December 31, 2007 the total remaining unrecognized amount of compensation expense related to stock-based compensation was approximately $4.6 million (before income taxes), which will be amortized over a weighted-average period of 2.3 years.

The Company has six share-based payment programs. The effect of SFAS No. 123(R) accounting on each of these programs is explained in the following paragraphs.

Purchase Plan

The Purchase Plan allows employees through payroll withholding to purchase shares of the Company's common stock at a 15% discount from the average market price on the last day of a six month investment period. Under SFAS 123(R), the Company is required to record compensation expense related to the 15% discount which was not required under APB No. 25. The 15% discount resulted in compensation expense of $257,000 in 2007 and $235,000 in 2006. The 15% discount is not taxable to the employee and is not a deductible expense for tax purposes for the Company.

Stock Options Granted Under the Incentive Plan

Since the inception of the Incentive Plan in 1999, the Company has granted 2,041,500 options for the purchase of the Company's common stock. All of the options granted had vested or were forfeited as of December 31, 2007. The exercise price of the options granted was the average market price of the Company's common stock on the grant date. These options were not compensatory under APB No. 25 accounting rules. Under SFAS No. 123(R) accounting, compensation expense is recorded based on the estimated fair value of the options on their grant date using a fair-value option pricing model. Under SFAS No. 123(R) accounting, the fair value of the options granted has been recorded as compensation expense over the requisite service period (the vesting period of the options). The estimated fair value of all options granted under the Incentive Plan has been based on the Black-Scholes option pricing model.

Under the modified prospective application of SFAS No. 123(R) accounting requirements, the difference between the intrinsic value of nonvested options and the fair value of those options of $362,000 on January 1, 2006 was recognized on a straight-line basis as compensation expense over the remaining 16 months of the options vesting period. Accordingly, the Company recorded compensation expense of $91,000 in 2007 and $271,000 in 2006 related to options that were not vested as of January 1, 2006.

Presented below is a summary of the stock options activity:

Stock Option Activity	2007		2006	
	Options	Average Exercise Price	Options	Average Exercise Price
Outstanding, Beginning of Year	1,091,238	$25.74	1,237,164	$25.58
Granted	--	--	--	--
Exercised	298,601	25.73	107,458	22.88
Forfeited	5,500	28.85	38,468	28.60
Outstanding, End of Year	787,137	25.73	1,091,238	25.74
Exercisable, End of Year	787,137	25.73	1,049,713	25.69
Cash Received for Options Exercised	$7,682,000		$2,458,000	
Granted During Year	none granted		none granted	

The following table summarizes information about options outstanding as of December 31, 2007:

Options Outstanding and Exercisable			
Range of Exercise Prices	Outstanding and Exercisable as of 12/31/07	Weighted-Average Remaining Contractual Life (yrs)	Weighted-Average Exercise price
$18.80-$21.94	175,210	2.0	$ 19.62
$21.95-$25.07	40,100	7.3	$ 24.93
$25.08-$28.21	429,927	4.0	$ 26.50
$28.22-$31.34	141,900	4.2	$ 31.17

Restricted Stock Granted to Directors

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to members of the Company's Board of Directors as a form of compensation. Under APB No. 25 accounting rules, the Company had recognized compensation expense for these restricted stock grants, ratably, over the four-year vesting period of the restricted shares based on the market value of the Company's common stock on the grant date. Under the modified prospective application of SFAS No. 123(R) accounting requirements, compensation expense related to nonvested restricted shares outstanding will be recorded based on the estimated fair value of the restricted shares on their grant dates. On April 9, 2007 the Compensation Committee of the Company's Board of Directors granted 15,200 shares of restricted stock to the Company's nonemployee directors under the Incentive Plan.

Presented below is a summary of the status of directors' restricted stock awards for the years ended December 31:

Directors' Restricted Stock Awards	2007		2006	
	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	32,775	$ 27.27	27,000	$ 26.32
Granted	15,200	$ 35.04	19,800	$ 28.24
Vested	13,875	$ 27.10	14,025	$ 26.82
Forfeited	--		--	
Nonvested, End of Year	34,100	$ 30.80	32,775	$ 27.27
Compensation Expense Recognized		$ 454,000		$ 401,000
Fair Value of Shares Vested in Year		$ 376,000		$ 376,000

Restricted Stock Granted to Employees

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to employees as a form of compensation. Under APB No. 25 accounting rules, the Company had recognized compensation expense for these restricted stock grants, ratably, over the vesting periods of the restricted shares based on the market value of the Company's common stock on the grant date. Because of income tax withholding provisions in the restricted stock award agreements related to restricted stock granted to employees prior to 2006, the value of these grants is considered variable, which, under SFAS No. 123(R), will require the offsetting credit to compensation expense to be recorded as a liability. Under the modified prospective application of SFAS No. 123(R) accounting requirements and accounting rules for variable awards, compensation expense related to nonvested restricted shares granted to employees will be recorded based on the estimated fair value of the restricted shares on their grant dates and adjusted for the estimated fair value of any nonvested restricted shares on each subsequent reporting date. The reporting date fair value of nonvested restricted shares granted prior to 2006 under this program is based on the average market value of the Company's common stock on the reporting date--$34.575 on December 31, 2007.

In 2006, under SFAS No. 123(R), the amount of compensation expense recorded related to nonvested restricted shares granted to employees was based on the estimated fair value of the restricted stock grants. In 2005, under APB No. 25, the amount of compensation expense recorded related to nonvested restricted shares granted to employees was based on the intrinsic value of the restricted stock grants. The equity account, Unearned Compensation, was credited when compensation expense was recorded related to these shares under APB No. 25 accounting. Under SFAS 123(R) accounting, a current liability account is credited when compensation expense is recorded. Accumulated liabilities related to nonvested restricted shares issued to employees under this program prior to 2006 will be reversed and credited to the Premium on Common Shares equity account as the shares vest.

In 2006, the income tax withholding provisions in the Company's restricted stock award agreements were revised to only allow withholding at statutory withholding rates. The fair value of restricted shares issued under the revised restricted stock award agreements is not considered a liability under SFAS No. 123(R), so compensation expense related to awards granted after 2005 will be based on their grant-date fair value and recognized over the vesting period of the awards with the offsetting credit charged directly to equity. On April 9, 2007 the Compensation Committee of the Company's Board of Directors granted 600 shares of restricted stock to a newly hired employee under the Incentive Plan. The restricted shares vest 50% on issuance and 50% on April 8, 2008 and are eligible for full dividend and voting rights. The grant-date fair value of the restricted shares was $35.30 per share, the average market price of the shares on their grant date. On October 29, 2007 the Compensation Committee of the Company's Board of Directors granted 16,700 shares of restricted stock to the Company's executive officers under the Incentive Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2008 through 2011 and are eligible for full dividend and voting rights. The grant-date fair value of the restricted shares was $35.84 per share, the average market price of the shares on their grant date.

Presented below is a summary of the status of employees' restricted stock awards for the years ended December 31:

Employees' Restricted Stock Awards	2007		2006	
	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value
Nonvested, Beginning of Year	31,666	$ 31.47	72,974	$ 28.91
Granted	17,300	$ 35.82	--	
Variable/Liability Awards Vested	24,608	$ 35.09	41,308	$ 28.98
Nonvariable Awards Vested	300	$ 35.30	--	
Forfeited	--		--	
Nonvested, End of Year	24,058	$ 35.46	31,666	$ 31.47
Compensation Expense Recognized		$ 549,000		$ 815,000
Fair Value of Variable Awards Vested/Liability Paid		$ 863,000		$1,197,000
Fair Value of Nonvariable Awards Vested		$ 11,000		--

Restricted Stock Units Granted to Employees

On April 9, 2007 the Compensation Committee of the Company's Board of Directors granted 23,450 restricted stock units to key employees under the Incentive Plan payable in common shares on April 8, 2011, the date the units vest. The Company uses a Monte Carlo valuation method to determine the grant-date fair value of restricted stock units. The grant-date fair value of each restricted stock unit granted on April 9, 2007 was $30.07 per share. The weighted average contractual term of stock units outstanding as of December 31, 2007 is 2.8 years.

Presented below is a summary of the status of employees' restricted stock unit awards for the years ended December 31:

	2007		2006	
	Restricted Stock Units	Weighted Average Grant-Date Fair Value	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	38,615	$ 24.65	--	$ --
Granted	23,450	$ 30.07	47,425	$ 25.41
Converted	4,850	$ 26.95	7,450	$ 29.55
Forfeited	1,735	$ 27.03	1,360	$ 24.36
Nonvested, End of Year	55,480	$ 26.66	38,615	$ 24.65
Compensation Expense Recognized		$ 383,000		$ 427,000
Fair Value of Units Converted in Year		$ 131,000		$ 220,000

Stock Performance Awards granted to Executive Officers

The Compensation Committee of the Company's Board of Directors has approved stock performance award agreements under the Incentive Plan for the Company's executive officers. Under these agreements, the officers could be awarded shares of the Company's common stock based on the Company's total shareholder return relative to that of its peer group of companies in the Edison Electric Institute (EEI) Index over a three-year period beginning on January 1 of the year the awards are granted. The number of shares earned, if any, will be awarded and issued at the end of each three-year performance measurement period. The participants have no voting or dividend rights under these award agreements until the shares are issued at the end of the performance measurement period. Under APB No. 25 accounting, these awards were valued based on the average market price of the underlying shares of the Company's common stock on the award grant date, multiplied by the estimated probable number of shares to be awarded at the end of the performance measurement period with compensation expenses recorded ratably over the related three-year measurement period. Compensation expense recognized was adjusted at each reporting date subsequent to the grant date of the awards for the difference between the market value of the underlying shares on their grant date and the market value of the underlying shares on the reporting date. Under the modified prospective application of SFAS No. 123(R) accounting requirements, the amount of compensation expense that will be recorded subsequent to January 1, 2006 related to awards granted in 2004 and 2005 and outstanding on December 31, 2006 is based on the estimated grant-date fair value of the awards as determined under the Black-Scholes option pricing model.

On October 29, 2007 the Compensation Committee of the Company's Board of Directors granted performance share awards to the Company's executive officers under the Incentive Plan. Under these awards, the Company's executive officers could earn up to an aggregate of 109,000 common shares based on the Company's total shareholder return relative to the total shareholder return of the companies that comprise the EEI Index over the performance period of January 1, 2007 through December 31, 2009. The aggregate target share award is 54,500 shares. Actual payment may range from zero to 200 percent of the target amount. The executive officers have no voting or dividend rights related to these shares until the shares, if any, are issued at the end of the performance period. In accordance with SFAS No. 123(R), the Company will estimate the fair value of the common shares projected to be awarded on the date of grant under a Monte Carlo valuation method and record compensation expense over the remaining performance period.

The offsetting credit to amounts expensed related to the stock performance awards is included in common shareholders' equity. The table below provides a summary of amounts expensed for the stock performance awards:

Performance Period	Maximum Shares Subject To Award	Shares Used To Estimate Expense	Fair Value	Expense Recognized in the Year Ended December 31, 2007	Expense Recognized in the Year Ended December 31, 2006	Shares Awarded
2007-2009	109,000	67,263	$38.01	$ 852,000	$ --	
2006-2008	88,050	58,700	$25.95	508,000	508,000	
2005-2007	75,150	50,872	$22.10	375,000	375,000	62,625
2004-2006	70,500	23,500	$23.90	--	187,000	23,500
Total				$1,735,000	$1,070,000	86,125

7. Retained Earnings Restriction

The Company's Articles of Incorporation, as amended, contain provisions that limit the amount of dividends that may be paid to common shareholders by the amount of any declared but unpaid dividends to holders of the Company's cumulative preferred shares. Under these provisions none of the Company's retained earnings were restricted at December 31, 2007.

8. Commitments and Contingencies

At December 31, 2007 the electric utility had commitments under contracts in connection with construction programs aggregating approximately $35,835,000. For capacity and energy requirements, the electric utility has agreements extending through 2032 at annual costs of approximately $23,111,000 in 2008, $22,929,000 in 2009, $11,377,000 in 2010, $5,565,000 in 2011 and $5,565,000 in 2012, and $93,286,000 for the years beyond 2012.

The electric utility has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. These contracts expire in 2010 and 2016. In total, the electric utility is committed to the minimum purchase of approximately $183,209,000 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.

The amounts of future operating lease payments are as follows in thousands:

2008	$ 2,560
2009	2,560
2010	2,203
2011	1,446
2012	951
Later years	3,206
Total	$12,926

The electric future operating lease payments are primarily related to coal rail-car leases. Rent expense was $2,461,000 for 2007 and $1,828,000 for 2006.

The Company is a party to litigation arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its comparative results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2007 will not be material.

9. Short-Term and Long-Term Borrowings

Short-Term Debt

As of December 31, 2007 the Company had no short-term debt outstanding. As of December 31, 2006 the Company had $38.9 million in short-term debt outstanding at a weighted average interest rate of 5.7%. The average interest rate paid on short-term debt was 6.0% in 2007 and 5.8% in 2006.

The Company's $150 million line of credit pursuant to a Credit Agreement dated as of April 26, 2006 with U.S. Bank National Association, JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association, Harris Nesbitt Financing, Inc., Keybank National Association, Union Bank of California, N.A., Bank of America, N.A., Bank Hapoalim B.M., and Bank of the West was scheduled to expire on April 26, 2009 but was terminated and replaced by a new $200 million credit agreement (the Varistar Credit Agreement) entered into by Varistar Corporation (Varistar), a wholly-owned subsidiary of the Company, on October 2, 2007. Varistar entered into the Varistar Credit Agreement with the following banks: U.S. Bank National Association, as agent for the Banks and as Lead Arranger, Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents, and JPMorgan Chase Bank, N.A., Bank of the West and Union Bank of California, N.A.

Otter Tail Corporation, dba Otter Tail Power Company and U.S. Bank National Association have a Credit Agreement (the Electric Utility Credit Agreement) providing for a separate $75 million line of credit. This line of credit is an unsecured revolving credit facility that the electric utility can draw on to support the working capital needs and other capital requirements of its electric operations. Borrowings under this line of credit bear interest at LIBOR plus 0.4%, subject to adjustment based on the ratings of the Company's senior unsecured debt. The Electric Utility Credit Agreement contains a number of restrictions on the business of the electric utility, 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 Electric Utility Credit is subject to renewal on September 1, 2008. As of December 31, 2007 no money was borrowed under the Electric Utility Credit Agreement.

Long-Term Debt

The Company has the ability to issue up to $256 million of common shares, cumulative preferred shares, debt and certain other securities from time to time under its universal shelf registration statement filed with the Securities and Exchange Commission on June 4, 2004 and declared effective on August 30, 2004. The Company issued no long-term debt under its universal shelf registration in 2007 or 2006.

At closings completed in August 2007 and October 2007, the Company issued $155 million aggregate principal amount of its senior unsecured notes, in a private placement transaction, to the purchasers named in a note purchase agreement (the 2007 Note Purchase Agreement) dated August 20, 2007. These notes were issued in four series: $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017 (the Series A Notes); $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022 (the Series B Notes); $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027 (the Series C Notes); and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (the Series D Notes). On August 20, 2007, $12 million aggregate principal amount of the Series C Notes and $13 million aggregate principal amount of the Series D Notes were issued and sold pursuant to the 2007 Note Purchase Agreement. The net proceeds from this initial closing were used to repay borrowings under the Company's $150 million line of credit that was terminated on October 2, 2007. The remaining $30 million aggregate principal amount of the Series C Notes and $37 million aggregate principal amount of the Series D Notes, as well as the Series A Notes and the Series B Notes, were issued and sold by the Company at a second closing on October 1, 2007. The net proceeds from the second closing were used to retire $40 million aggregate principal amount of the Company's 5.625% Series of Insured Senior Notes due October 1, 2017 and $25 million aggregate principal amount of the Company's 6.80% Series of Senior Notes due October 1, 2032 on October 15, 2007, to pay down lines of credit and to fund capital expenditures.

In February 2007 the Company entered into a note purchase agreement (the Cascade Note Purchase Agreement) with Cascade Investment L.L.C. (Cascade) pursuant to which the Company agreed to issue to Cascade, in a private placement transaction, $50 million aggregate principal amount of the Company's senior notes due November 30, 2017 (the Cascade Note). On December 14, 2007 the Company issued the Cascade Note. The Cascade Note bears interest at a rate of

5.778% per annum. The terms of the Cascade Note Purchase Agreement are substantially similar to the terms of the note purchase agreement entered into in connection with the issuance of the Company's $90 million 6.63% senior notes due December 1, 2011 (the 2001 Note Purchase Agreement). The proceeds of this financing were used to redeem the Company's $50 million 6.375% Senior Debentures due December 1, 2007. Cascade owned approximately 8.6% of the Company's outstanding common stock as of December 31, 2007.

Each of the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement, and the 2001 Note Purchase Agreement states the Company 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. Each of the Cascade Note Purchase Agreement and the 2001 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require the Company 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 respective note purchase agreements. The 2007 Note Purchase Agreement states the Company 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 the Company.

The 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the Cascade Note Purchase Agreement contain a number of restrictions on the businesses of the Company and its subsidiaries. In each case these include restrictions on the ability of the Company and certain of its subsidiaries 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 Company's obligations under the 2001 Note Purchase Agreement and the Cascade Note Purchase Agreement are guaranteed by certain of its subsidiaries. Varistar's obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries. The Company's Grant County and Mercer County Pollution Control Refunding Revenue Bonds require that the Company grant to Ambac Assurance Corporation, under a financial guaranty insurance policy relating to the bonds, a security interest in the assets of the electric utility if the rating on the Company's senior unsecured debt is downgraded to Baa2 or below (Moody's) or BBB or below (Standard & Poor's).

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2007 for each of the next five years are $2,328,572 for 2008, $2,328,572 for 2009, $2,328,568 for 2010, $90,000,000 for 2011 and $10,400,000 for 2012.

Financial Covenants

The Electric Utility Credit Agreement, the 2001 Note Purchase Agreement, the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement and the Lombard US Equipment Finance note contain covenants by the Company not to permit its debt-to-total capitalization ratio to exceed 60% or permit its interest and dividend coverage ratio (or in the case of the Cascade Note Purchase Agreement, the Company's interest coverage ratio) to be less than 1.5 to 1. The note purchase agreements further restrict the Company from allowing its priority debt to exceed 20% of total capitalization. Financial covenants in the Varistar Credit Agreement require Varistar to maintain a fixed charge coverage ratio of not less than 1.25 to 1 and to not permit its cash flow leverage ratio to exceed 3.0 to 1. The Company and Varistar were in compliance with all of the covenants under their financing agreements as of December 31, 2007.

10. Pension Plan and Other Postretirement Benefits

The following footnote reflects the adoption of SFAS No. 158, *Accounting for Defined Benefit Pension and Other Postretirement Plans,* in December 2006. The Company determined that the balance of unrecognized net actuarial losses, prior service costs and the SFAS No. 106 transition obligation related to regulated utility activities would be subject to recovery through rates as those balances are amortized to expense and the related benefits are earned. Therefore, the Company charged those unrecognized amounts to regulatory asset accounts under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, rather than to Accumulated Other Comprehensive Losses in equity as prescribed by SFAS No. 158.

Pension Plan

The Company's noncontributory funded pension plan covers substantially all electric utility and corporate 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. The Company reserves the right to discontinue the plan but no change or discontinuance may affect the pensions theretofore vested. The Company's policy is to fund pension costs accrued. All past service costs have been provided for.

The pension plan has a trustee who is responsible for pension payments to retirees. Four investment managers are responsible for managing the plan's assets. An independent actuary assists the Company 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 the Company.

Components of net periodic pension benefit cost:

(in thousands)	2007	2006
Service Cost--Benefit Earned During the Period	$ 4,837	$ 5,057
Interest Cost on Projected Benefit Obligation	10,790	10,435
Expected Return on Assets	(12,948)	(12,288)
Amortization of Prior-Service Cost	742	742
Amortization of Net Actuarial Loss	1,091	1,844
Net Periodic Pension Cost	$ 4,512	$ 5,790

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

(in thousands)	2007	2006
Regulatory Assets:		
Unrecognized Prior Service Cost	$ (4,018)	$ (4,748)
Unrecognized Actuarial Loss	(17,115)	(21,771)
Total Regulatory Assets	(21,133)	(26,519)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	(120)	(132)
Unrecognized Actuarial Loss	(511)	(606)
Total Accumulated Other Comprehensive Loss	(631)	(738)
Prepaid Pension Cost	7,493	8,005
Net Amount Recognized – Noncurrent Liability	$ (14,271)	$ (19,252)

Funded status as of December 31:

(in thousands)	2007	2006
Accumulated Benefit Obligation	$(154,373)	$(153,816)
Projected Benefit Obligation	$(185,206)	$(186,760)
Fair Value of Plan Assets	170,935	167,508
Funded Status	$ (14,271)	$ (19,252)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's benefit obligations and prepaid pension cost over the two-year period ended December 31, 2007:

(in thousands)	2007	2006
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ 167,508	$ 146,982
Actual Return on Plan Assets	8,013	24,856
Discretionary Company Contributions	4,000	4,000
Benefit Payments	(8,586)	(8,330)
Fair Value of Plan Assets at December 31	$ 170,935	$ 167,508
Estimated Asset Return	4.85%	17.24%
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 186,760	$ 181,587
Service Cost	4,837	5,057
Interest Cost	10,790	10,435
Benefit Payments	(8,586)	(8,330)
Actuarial Gain	(8,595)	(1,989)
Projected Benefit Obligation at December 31	$ 185,206	$ 186,760
Reconciliation of Prepaid Pension Cost:		
Prepaid Pension Cost at January 1	$ 8,005	$ 9,795
Net Periodic Pension Cost	(4,512)	(5,790)
Discretionary Company Contributions	4,000	4,000
Prepaid Pension Cost at December 31	$ 7,493	$ 8,005

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

	2007	2006
Discount Rate	6.25%	6.00%
Rate of Increase in Future Compensation Level	3.75%	3.75%

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

	2007	2006
Discount Rate	6.00%	5.75%
Long-Term Rate of Return on Plan Assets	8.50%	8.50%
Rate of Increase in Future Compensation Level	3.75%	3.75%

To develop the expected long-term rate of return on assets assumption, the Company 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--The Company's expected return on plan assets is determined based on the expected long-term rate of return on plan assets and the market-related value of plan assets.

The Company 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 gain 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 2008 net periodic pension cost is 8.50%.

Measurement Dates:	2007	2006
Net Periodic Pension Cost	January 1, 2007	January 1, 2006
End of Year Benefit Obligations	January 1, 2007 projected to December 31, 2007	January 1, 2006 projected to December 31, 2006
Market Value of Assets	December 31, 2007	December 31, 2006

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 2008 are:

(in thousands)	2008
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 720
Amortization of Unrecognized Actuarial Loss	103
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	22
Amortization of Unrecognized Actuarial Loss	3
Total Estimated Amortization	$ 848

Cash flows--The Company is not required to make a contribution to the pension plan in 2008.

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

(in thousands)	2008	2009	2010	2011	2012	Years 2013-2017
	$8,917	$9,073	$9,234	$9,641	$10,103	$59,365

The Company's pension plan asset allocations at December 31, 2007 and 2006, by asset category are as follows:

Asset Allocation	2007	2006
Large Capitalization Equity Securities	47.1%	49.3%
Small Capitalization Equity Securities	10.7%	11.6%
International Equity Securities	10.4%	10.6%
Total Equity Securities	68.2%	71.5%
Cash and Fixed-Income Securities	31.8%	28.5%
	100.0%	100.0%

The following objectives guide the investment strategy of the Company's pension plan (the Plan).

- The Plan is managed to operate in perpetuity.
- The Plan will meet the pension benefit obligation payments of the Company.
- 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 the Company'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 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 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.

The Company's Retirement Plans Administrative Committee monitors actual asset allocations and directs contributions and withdrawals toward maintaining the targeted allocation percentages listed in the table below.

Asset Allocation	Strategic Target	Tactical Range
Large capitalization equity securities	48%	40%-55%
Small capitalization equity securities	12%	9%-15%
International equity securities	10%	5%-15%
Total equity securities	70%	60%-80%
Fixed-income securities	30%	20%-40%

Executive Survivor and Supplemental Retirement Plan (ESSRP)

The ESSRP is an unfunded, nonqualified benefit plan for 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. Life insurance carried on certain plan participants is payable to the Company on the employee's death. There are no plan assets in this nonqualified benefit plan due to the nature of the plan.

On December 19, 2006 the Board of Directors of the Company approved an amendment to the ESSRP effective January 1, 2006. The Amendment amends the ESSRP to provide that for each of the Company's Chief Executive Officer and Corporate Secretary, the "Normal Retirement Benefit" (as defined in the ESSRP) will be determined based on "Final Average Earnings" rather than "Final Annual Salary" (defined as the base Salary (as defined in the ESSRP) and annual bonus paid to the participant during the 12 months prior to termination or death). The ESSRP defines "Final Average Earnings" as the average of the participant's total cash payments (Salary (as defined in the ESSRP) and annual incentive bonus) paid during the highest consecutive 42 months in the 10 years prior to the date as of which the Final Average Earnings are determined.

Components of net periodic pension benefit cost:

(in thousands)	2007	2006
Service Cost--Benefit Earned During the Period	$ 626	$ 426
Interest Cost on Projected Benefit Obligation	1,451	1,303
Amortization of Prior-Service Cost	67	71
Amortization of Net Actuarial Loss	540	473
Net Periodic Pension Cost	$ 2,684	$ 2,273

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

(in thousands)	2007	2006
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 435	$ 496
Unrecognized Actuarial Loss	4,841	5,796
Total Regulatory Assets	5,276	6,292
Projected Benefit Obligation Liability – Net Amount Recognized	(25,158)	(24,783)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	266	271
Unrecognized Actuarial Loss	2,954	3,162
Total Accumulated Other Comprehensive Loss	3,220	3,433
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (16,662)	$ (15,058)

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, 2007 and a statement of the funded status as of December 31 of both years:

(in thousands)	2007	2006
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ --	$ --
Actual Return on Plan Assets	--	--
Employer Contributions	1,079	1,124
Benefit Payments	(1,079)	(1,124)
Fair Value of Plan Assets at December 31	$ --	$ --
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 24,783	$ 23,271
Service Cost	626	426
Interest Cost	1,451	1,303
Benefit Payments	(1,079)	(1,124)
Plan Amendments	--	(53)
Actuarial (Gain) Loss	(623)	960
Projected Benefit Obligation at December 31	$ 25,158	$ 24,783
Reconciliation of Funded Status:		
Funded Status at December 31	$ (25,158)	$ (24,783)
Unrecognized Net Actuarial Loss	7,795	8,958
Unrecognized Prior Service Cost	701	767
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (16,662)	$ (15,058)

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

	2007	2006
Discount Rate	6.25%	6.00%
Rate of Increase in Future Compensation Level	4.70%	4.71%

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

	2007	2006
Discount Rate	6.00%	5.75%
Rate of Increase in Future Compensation Level	4.71%	4.69%

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 2008 are:

(in thousands)	2008
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 42
Amortization of Unrecognized Actuarial Loss	298
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	25
Amortization of Unrecognized Actuarial Loss	182
Total Estimated Amortization	$ 547

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)	2008	2009	2010	2011	2012	Years 2013-2017
	$1,109	$1,114	$1,113	$1,206	$1,258	$6,755

Other Postretirement Benefits

The Company provides a portion of health insurance and life insurance benefits for retired electric utility and corporate employees. Substantially all of the Company's electric utility and corporate 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, the Company elected to recognize its transition obligation related to postretirement benefits earned of approximately $14,964,000 over a period of 20 years. There are no plan assets.

Components of net periodic postretirement benefit cost:

(in thousands)	2007	2006
Service Cost--Benefit Earned During the Period	$ 1,098	$ 1,319
Interest Cost on Projected Benefit Obligation	2,565	2,556
Amortization of Transition Obligation	748	748
Amortization of Prior-Service Cost	(206)	(305)
Amortization of Net Actuarial Loss	177	556
Expense Decrease Due to Medicare Part D Subsidy	(1,233)	(1,543)
Net Periodic Postretirement Benefit Cost	$ 3,149	$ 3,331

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

(in thousands)	2007	2006
Regulatory Asset:		
Unrecognized Transition Obligation	$ 3,658	$ 4,414
Unrecognized Prior Service Cost	1,781	1,588
Unrecognized Net Actuarial Gain	(4,915)	(2,077)
Net Regulatory Asset	524	3,925
Projected Benefit Obligation Liability – Net Amount Recognized	(30,488)	(32,254)
Accumulated Other Comprehensive Loss:		
Unrecognized Transition Obligation	83	75
Unrecognized Prior Service Cost	40	27
Unrecognized Net Actuarial Gain	(111)	(35)
Accumulated Other Comprehensive Loss	12	67
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (29,952)	$ (28,262)

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, 2007:

(in thousands)	2007	2006
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ --	$ --
Actual Return on Plan Assets	--	--
Company Contributions	1,459	2,051
Benefit Payments (Net of Medicare Part D Subsidy)	(3,127)	(3,625)
Participant Premium Payments	1,668	1,574
Fair Value of Plan Assets at December 31	$ --	$ --
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 32,254	$ 36,757
Service Cost (Net of Medicare Part D Subsidy)	890	1,110
Interest Cost (Net of Medicare Part D Subsidy)	1,776	1,779
Benefit Payments (Net of Medicare Part D Subsidy)	(3,127)	(3,625)
Participant Premium Payments	1,668	1,574
Actuarial Gain	(2,973)	(5,341)
Projected Benefit Obligation at December 31	$ 30,488	$ 32,254
Reconciliation of Accrued Postretirement Cost:		
Accrued Postretirement Cost at January 1	$ (28,262)	$ (26,982)
Expense	(3,149)	(3,331)
Net Company Contribution	1,459	2,051
Accrued Postretirement Cost at December 31	$ (29,952)	$ (28,262)

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

	2007	2006
Discount Rate	6.25%	6.00%

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

	2007	2006
Discount Rate	6.00%	5.75%

Assumed healthcare cost-trend rates as of December 31:

	2007	2006
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	8.00%	9.00%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	9.00%	10.00%
Rate at Which the Cost-Trend Rate is Assumed to Decline	5.00%	5.00%
Year the Rate Reaches the Ultimate Trend Rate	2012	2012

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 2007 would have the following effects:

(in thousands)	1 point increase	1 point decrease
Effect on the Postretirement Benefit Obligation	$ 2,804	$(2,423)
Effect on Total of Service and Interest Cost	$ 358	$ (293)
Effect on Expense	$ 418	$ (544)

Measurement dates:	2007	2006
Net Periodic Postretirement Benefit Cost	January 1, 2007	January 1, 2006
End of Year Benefit Obligations	January 1, 2007 projected to December 31, 2007	January 1, 2006 projected to December 31, 2006

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 2008 are:

(in thousands)	2008
Decrease in Regulatory Assets:	
Amortization of Transition Obligation	$ 732
Amortization of Unrecognized Prior Service Cost	205
Amortization of Unrecognized Actuarial Gain	(200)
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Transition Obligation	16
Amortization of Unrecognized Prior Service Cost	5
Amortization of Unrecognized Actuarial Gain	(4)
Total Estimated Amortization	$ 754

Cash flows--The Company expects to contribute $2.2 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2008. The Company expects to receive a Medicare Part D subsidy from the Federal government of approximately $386,000 in 2008. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(in thousands)	2008	2009	2010	2011	2012	Years 2013-2017
	$2,213	$2,266	$2,310	$2,294	$2,403	$13,263

Leveraged Employee Stock Ownership Plan

The Company has a leveraged employee stock ownership plan for the benefit of all its electric utility employees. Contributions made by the Company were $733,000 for 2007 and $738,000 for 2006.

11. Fair Value of Financial Instruments

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

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

Other Investments--The carrying amount approximates fair value. A portion of other investments is in financial instruments that have variable interest rates that reflect fair value.

Long-Term Debt--The fair value of the Company's long-term debt is estimated based on the current rates available to the Company for the issuance of debt. About $10.4 million of the Company's long-term debt, which is subject to variable interest rates, approximates fair value.

(in thousands)	December 31, 2007		December 31, 2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-Term Investments	$ 27,304	$ 27,304	$ 9,542	$ 9,542
Other Investments	3,022	3,022	3,314	3,314
Long-Term Debt	(338,276)	(349,824)	(250,634)	(260,745)

12. Property, Plant and Equipment

(in thousands)	December 31, 2007	December 31, 2006
Electric Plant		
Production	$ 439,541	$ 360,304
Transmission	191,949	189,683
Distribution	322,107	307,825
General	75,320	72,877
Electric Plant	1,028,917	930,689
Less Accumulated Depreciation and Amortization	446,475	433,657
Electric Plant Net of Accumulated Depreciation	582,442	497,032
Construction Work in Progress	33,772	18,502
Net Electric Plant	$ 616,214	$ 515,534

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

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

13. Summary Information of Investees Accounted for Under the Equity Method

See note 1 for further discussion.

	2007	2006
	(in thousands)	
Net property, plant, and equipment	$ 190,473	$ 156,016
Current assets	290,773	128,299
Other assets	132,929	251,237
Total assets	$ 614,175	$ 535,552
Current and other liabilities	$ 222,844	$ 200,675
Long-term liabilities	43,892	32,323
Class B stock options	1,255	1,255
Owner's equity	346,184	301,299
Total liabilities and equity	$ 614,175	$ 535,552
Operating revenue	$ 922,012	$ 832,287
Operating expenses	862,119	781,067
Operating income	59,893	51,220
Other income, deductions, and interest	(8,635)	(7,770)
Income taxes	18,047	15,509
Net income	$ 33,211	$ 27,941

14. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35 percent in 2007 and 2006) to net income before total income tax expense for the following reasons:

	2007	2006
	(in thousands)	
Tax computed at federal statutory rate	$ 10,879	$ 12,257
Increases (decreases) in tax from:		
State income taxes net of federal income tax benefit	987	1,094
Investment tax credit amortization	(1,137)	(1,146)
Depreciation differences--flow-through method reversal		
Timing differences reversing in excess of federal rates	929	1,271
Dividends received/paid deduction	(714)	(718)
Affordable housing tax credits	(285)	(839)
Section 199 deduction	(327)	(205)
Permanent and other differences	(267)	135
Total income tax expense	$ 10,065	$ 11,849

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	/ /	2007/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

	2007	2006
Overall effective federal and state income tax rate	32.3%	32.2%
	(in thousands)	
Income tax expense includes the following:		
Charges (credits) related to operations:		
Current federal income taxes	$ 6,043	$ 11,786
Current state income taxes	(863)	1,830
Deferred federal income taxes	2,701	(484)
Deferred state income taxes	733	(8)
Investment tax credit amortization	(1,136)	(1,145)
Total	7,478	11,979
Charges (credits) related to other income and deductions:		
Current federal income taxes	2,146	2,529
Current state income taxes	131	668
Affordable housing tax credits	(285)	(839)
Deferred federal income taxes	(847)	(2,093)
Deferred state income taxes	1,442	(395)
Total income tax expense	$ 10,065	$ 11,849

The Company's deferred tax assets and liabilities were composed of the following on December 31, 2007 and 2006:

	2007	2006
	(in thousands)	
Deferred tax assets		
Amortization of tax credits	$ 4,505	$ 5,231
Vacation accrual	1,258	1,230
Operating reserves	27,103	24,819
Differences related to property	8,270	7,253
Transfer to regulatory liability/(asset)	(261)	(308)
Related to ND Wind Tax Credit	12,999	-
Other	678	688
Total deferred tax assets	54,552	38,913
Deferred tax liabilities		
Differences related to property	(109,710)	(103,635)
Excess tax over book pension	(2,953)	(3,153)
Transfer to regulatory asset	(8,471)	(11,404)
Related to ND Wind Tax Credit	(4,340)	-
Other	(377)	128
Total deferred tax liabilities	(125,851)	(118,064)
Deferred income taxes	$ (71,299)	$ (79,151)

On January 1, 2007 the Company adopted the provisions of FIN No. 48. The cumulative effect of adoption of FIN No. 48, which is reported as an adjustment to the beginning balance of retained earnings, was $118,000. As of the date of adoption, the total amount of unrecognized tax benefits for uncertain tax positions was $1,874,000. The amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate was $575,000 as of January 1, 2007.

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

(in thousands)	Total
Balance at January 1, 2007	$ 1,874
Increases Related to Current Year Tax Positions	198
Expiration of the Statute of Limitations for the Assessment of Taxes	(1,566)
Balance at December 31, 2007	$ 506

The balance of unrecognized tax benefits as of December 31, 2007 would reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2007 is not expected to change significantly within the next 12 months. The Company and its subsidiaries file a comparative U.S. federal income tax return and various state and foreign income tax returns. As of December 31, 2007 the Company is no longer subject to U.S. federal income tax examinations by tax authorities for years before 2004. As of December 31, 2007 the Company's earliest open tax year in which an audit can be initiated by state taxing authorities in the Company's major operating jurisdictions is 2003 for Minnesota and 2004 for North Dakota. Amounts accrued for interest and penalties on tax uncertainties as of December 31, 2007 were not material.

15. Asset Retirement Obligations (AROs)

The Company's AROs are related to coal-fired generation plants and 27 wind turbines erected near Langdon, North Dakota and include site restoration, closure of ash pits, and removal of storage tanks, structures, generators and asbestos. The Company 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. The Company has no assets legally restricted for the settlement of any of its AROs.

During 2007, the Company recorded new obligations related to the removal of 27 wind turbines erected near Langdon, North Dakota and restoration of the tower sites but did not make any revisions to previously recorded obligations.

During 2006, the Company did not record any new obligation or make any revisions to previously recorded obligations. The Company settled a legal obligation for removal of asbestos at unit one of its Hoot Lake generating plant.

Reconciliations of carrying amounts of the present value of the Company's legal AROs, capitalized asset retirement costs and related accumulated depreciation and a summary of settlement activity for the years ended December 31, 2007 and 2006 are presented in the following table:

(in thousands)	2007	2006
Asset Retirement Obligations		
Beginning Balance	$ 1,335	$ 1,524
New Obligations Recognized	1,024	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Accrued Accretion	88	85
Settlements	--	(274)
Ending Balance	$ 2,447	$ 1,335
Asset Retirement Costs Capitalized		
Beginning Balance	$ 285	$ 349
New Obligations Recognized	1,024	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Settlements	--	(64)
Ending Balance	$ 1,309	$ 285
Accumulated Depreciation - Asset Retirement Costs Capitalized		
Beginning Balance	$ 178	$ 234
New Obligations Recognized	--	--
Adjustments Due to Revisions in Cash Flow Estimates	--	--
Accrued Depreciation	7	8
Settlements	--	(64)
Ending Balance	$ 185	$ 178
Settlements		
Original Capitalized Asset Retirement Cost - Retired	$ --	$ 64
Accumulated Depreciation	--	(64)
Asset Retirement Obligation	$ --	$ 274
Settlement Cost	--	(222)
Gain on Settlement – Deferred Under Regulatory Accounting	$ --	$ 52

16. Quantitative and Qualitative Disclosures About Market Risk

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, 2007 we had $10.4 million of long-term debt subject to variable interest rates. 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, 2007, annualized interest expense on variable rate long-term debt 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.

The electric utility has market, price and credit risk associated with forward contracts for the purchase and sale of electricity. As of December 31, 2007 the electric utility had recognized, on a pretax basis, $632,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. 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 the electric utility's forward contracts for the purchases and sales of electricity are determined by survey of counterparties or brokers used by the electric utility'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. Prices are benchmarked to forward price curves and indices acquired from a third party price forecasting service. Of the forward energy sales contracts that are marked to market as of December 31, 2007, 97.6% are offset by forward energy purchase contracts in terms of volumes and delivery periods, with $56,000 in unrealized gains recognized on the open sales contracts.

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. Exposure to price risk on any open positions as of December 31, 2007 was not material.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity on our comparative balance sheet as of December 31, 2007 and the change in our comparative balance sheet position from December 31, 2006 to December 31, 2007:

(in thousands)	December 31, 2007
Current Asset – Marked-to-Market Gain	$ 5,210
Regulatory Asset – Deferred Marked-to-Market Loss	771
Total Assets	5,981
Current Liability – Marked-to-Market Loss	(5,078)
Regulatory Liability – Deferred Marked-to-Market Gain	(271)
Total Liabilities	(5,349)
Net Fair Value of Marked-to-Market Energy Contracts	$ 632

(in thousands)	Year ended December 31, 2007
Fair Value at Beginning of Year	$ 203
Amount Realized on Contracts Entered into in 2006 and Settled in 2007	(203)
Changes in Fair Value of Contracts Entered into in 2006	--
Net Fair Value of Contracts Entered into in 2006 at Year End 2007	--
Changes in Fair Value of Contracts Entered into in 2007	632
Net Fair Value at End of Year	$ 632

The $632,000 in recognized but unrealized net gains on the forward energy purchases and sales marked to market on December 31, 2007 is expected to be realized on physical settlement as scheduled over the following quarters in the amounts listed:

(in thousands)	1st Quarter 2008	4th Quarter 2008	Total
Net Gain	$ 118	$ 514	$ 632

We have credit risk associated with the nonperformance or nonpayment by counterparties to our forward energy purchases and sales agreements. We have established guidelines and limits to manage credit risk associated with wholesale power purchases and sales. Specific limits are determined by a counterparty's financial strength. Our credit risk with our largest counterparty on delivered and marked-to-market forward contracts as of December 31, 2007 was $0.5 million. As of December 31, 2007 we had a net credit risk exposure of $1.5 million from eight counterparties with investment grade credit ratings and one counterparty that has not been rated by an external credit rating agency but has been evaluated internally and assigned an internal credit rating equivalent to investment grade. We had no exposure at December 31, 2007 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 $1.5 million credit risk exposure includes net amounts due to the electric utility 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, 2007. 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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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.

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	(37,497)	(7,552,691)		1,451,704
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value	55,450	7,552,691		(2,536,582)
4	Total (lines 2 and 3)	55,450	7,552,691		(2,536,582)
5	Balance of Account 219 at End of Preceding Quarter/Year	17,953			(1,084,878)
6	Balance of Account 219 at Beginning of Current Year	17,953			(1,084,878)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value	3,747			2,243,880
9	Total (lines 7 and 8)	3,747			2,243,880
10	Balance of Account 219 at End of Current Quarter/Year	21,700			1,159,002

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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			(6,138,484)		
2					
3			5,071,559		
4			5,071,559	51,111,752	56,183,311
5			(1,066,925)		
6			(1,066,925)		
7					
8			2,247,627		
9			2,247,627	53,960,704	56,208,311
10			1,180,702		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2007/Q4

FOOTNOTE DATA

Schedule Page: 122(a)(b) Line No.: 3 Column: c

The 2006 change in fair value is $4,257,192. An additional $752,808 was recorded due to SFAS No. 158 that relates to accumulated (not current-year) comprehensive income. The total of those two amounts is $5,010,000. This page does not allow us to distinguish between current-year and prior-year amounts. The total comprehensive income for 2006 is $55,430,503, which is the amount of $56,183,311 (from line 4, column j) less the $752,808.

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 (f) 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)	956,823,748	956,823,748
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	70,416,600	70,416,600
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,027,240,348	1,027,240,348
9	Leased to Others		
10	Held for Future Use	29,656	29,656
11	Construction Work in Progress	33,772,360	33,772,360
12	Acquisition Adjustments	1,647,128	1,647,128
13	Total Utility Plant (8 thru 12)	1,062,689,492	1,062,689,492
14	Accum Prov for Depr, Amort, & Depl	446,475,444	446,475,444
15	Net Utility Plant (13 less 14)	616,214,048	616,214,048
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	443,528,519	443,528,519
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	1,687,402	1,687,402
22	Total In Service (18 thru 21)	445,215,921	445,215,921
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	1,259,523	1,259,523
33	Total Accum Prov (equals 14) (22,26,30,31,32)	446,475,444	446,475,444

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
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					31
					32
					33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

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
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
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			21
			22

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	2,081,307	1,148,556
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	3,383,281	1,148,556
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,247,790	
9	(311) Structures and Improvements	58,790,094	283,577
10	(312) Boiler Plant Equipment	179,641,665	10,257,247
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	51,948,226	7,427,129
13	(315) Accessory Electric Equipment	19,002,332	36,239
14	(316) Misc. Power Plant Equipment	5,112,379	125,599
15	(317) Asset Retirement Costs for Steam Production	285,405	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	316,027,891	18,129,791
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	181,824	9,156
29	(332) Reservoirs, Dams, and Waterways	1,412,321	47,134
30	(333) Water Wheels, Turbines, and Generators	808,123	116,117
31	(334) Accessory Electric Equipment	478,134	
32	(335) Misc. Power PLant Equipment	148,909	
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)	3,336,934	172,407
36	D. Other Production Plant		
37	(340) Land and Land Rights	126,762	
38	(341) Structures and Improvements	4,597,992	11,985
39	(342) Fuel Holders, Products, and Accessories	1,547,234	
40	(343) Prime Movers	31,091,977	-120,898
41	(344) Generators		65,000,000
42	(345) Accessory Electric Equipment	1,594,131	
43	(346) Misc. Power Plant Equipment	392,873	4,376
44	(347) Asset Retirement Costs for Other Production		1,024,097
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	39,350,969	65,919,560
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	358,715,794	84,221,758

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	381,100	
49	(352) Structures and Improvements		
50	(353) Station Equipment	54,429,052	1,510,709
51	(354) Towers and Fixtures	4,692,263	
52	(355) Poles and Fixtures	66,468,142	663,581
53	(356) Overhead Conductors and Devices	63,586,604	413,377
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices	69,529	481
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)	189,626,690	2,588,148
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	992,448	
61	(361) Structures and Improvements		
62	(362) Station Equipment	42,694,311	2,820,379
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	52,194,014	1,965,477
65	(365) Overhead Conductors and Devices	41,413,154	724,941
66	(366) Underground Conduit	10,879	
67	(367) Underground Conductors and Devices	48,743,740	2,966,937
68	(368) Line Transformers	49,472,859	4,655,291
69	(369) Services	36,629,547	1,675,218
70	(370) Meters	28,069,726	2,151,405
71	(371) Installations on Customer Premises	3,578,502	242,805
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	3,993,224	289,638
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	307,792,404	17,492,091
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	1,273,505	4,649
87	(390) Structures and Improvements	26,959,703	118,801
88	(391) Office Furniture and Equipment	7,192,208	1,860,794
89	(392) Transportation Equipment	24,896,982	1,451,049
90	(393) Stores Equipment	14,350	
91	(394) Tools, Shop and Garage Equipment	3,140,312	1,041,232
92	(395) Laboratory Equipment	454,194	
93	(396) Power Operated Equipment	496,188	
94	(397) Communication Equipment	5,066,308	223,390
95	(398) Miscellaneous Equipment		
96	SUBTOTAL (Enter Total of lines 86 thru 95)	69,493,750	4,699,915
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)	69,493,750	4,699,915
100	TOTAL (Accounts 101 and 106)	929,011,919	110,150,468
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)	929,011,919	110,150,468

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
445,077			2,784,786		4
445,077			4,086,760		5
					6
					7
			1,247,790		8
36,892			59,036,779		9
4,373,830			185,525,082		10
					11
455,261			58,920,094		12
18,494			19,020,077		13
82,733			5,155,245		14
			285,405		15
4,967,210			329,190,472		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			307,623		27
2,590			188,390		28
6,564			1,452,891		29
7,126			917,114		30
			478,134		31
1,017			147,892		32
					33
					34
17,297			3,492,044		35
					36
			126,762		37
			4,609,977		38
			1,547,234		39
			30,971,079		40
			65,000,000		41
			1,594,131		42
			397,249		43
			1,024,097		44
			105,270,529		45
4,984,507			437,953,045		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
19,618			361,482		48
					49
192,858		-302,906	55,443,997		50
			4,692,263		51
68,873			67,062,850		52
51,857			63,948,124		53
					54
			70,010		55
					56
					57
333,206		-302,906	191,578,726		58
					59
31,915			960,533		60
					61
837,310		356,938	45,034,318		62
					63
90,664			54,068,827		64
143,653		4,057	41,998,499		65
			10,879		66
210,688			51,499,989		67
486,133		-40,432	53,601,585		68
35,633			38,269,132		69
1,135,044			29,086,087		70
130,374			3,690,933		71
					72
97,317			4,185,545		73
					74
3,198,731		320,563	322,406,327		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
1,746			1,276,408		86
43,987		-17,657	27,016,860		87
1,204,543			7,848,459		88
1,376,878			24,971,153		89
13,804			546		90
173,329			4,008,215		91
78,570			375,624		92
			496,188		93
67,661			5,222,037		94
					95
2,960,518		-17,657	71,215,490		96
					97
					98
2,960,518		-17,657	71,215,490		99
11,922,039			1,027,240,348		100
					101
					102
					103
11,922,039			1,027,240,348		104

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			29,656

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Ottertail, MN - Construct new line	107,524
2	System Wide - Purchase transformers	509,985
3	System Wide - Purchase regulators	348,573
4	System Wide - Cyber security implementation	180,437
5	System Wide - EP node metering at substations	192,756
6	Crookston, MN - Transmission line rebuild	121,044
7	System Wide - Circuit breaker purchases	118,745
8	Solway, MN - Generator Controls Upgrade	128,277
9	Jamestown, ND - Generator ring replacement	516,473
10	Ottertail, MN - Build new substation	114,509
11	Hoffman, MN - Distribution upgrade	100,204
12	Fergus Falls, MN - Replace feedwater heater	138,264
13	Fergus Falls, MN - Purchase land	196,261
14	Fergus Falls, MN - Refurbish King Air plane	135,302
15	Fergus Falls, MN - Addition to Hi-Tech building	649,897
16	Fergus Falls, MN - Upgrade unit 2 burner	768,759
17	Sanborn, ND - Valley City, ND - Line reroute around lake	147,878
18	Hensel, ND - Substion control and relaying	402,359
19	Fergus Falls, MN - Retube economizer	1,071,351
20	Morris, MN - Substation replacement	107,197
21	Clearbrook, MN - Substation expansion	568,128
22	Bemidji, MN - Transmission line upgrade	315,424
23	Fargo, ND - St. Cloud, MN - Construct transmission line	212,843
24	Brookings, SD - SE Twin Cities, MN - Construct transmission line	165,722
25	Big Stone City, SD - Replace circulating water pump	342,841
26	Beulah, ND - Replace section of reheat outlet	197,177
27	Beulah, ND - Upgrade HP-IP turbine rotor	1,027,101
28	Langdon, ND - Construct wind turbine farm	6,217,910
29	Big Stone City, SD - Construct communication tower	137,734
30	Dawson, MN - Substation upgrade	160,954
31	Crookston, MN - Install Circuit Switcher	244,296
32	Crookston, MN - New substation	122,747
33	Big Stone City, SD - Construct New Power Plant	8,042,623
34	Big Stone City, SD - Land purchase	185,118
35	Beulah, ND - Purchase GSU transformer	955,200
36	Green Valley, MN - Replace transformer	104,304
37	Appleton, MN - Transmission line upgrade	1,187,513
38	Appleton, MN - Transmission line rebuild	671,983
39	Miscellaneous Work Orders Less than $100,000	6,856,947
40		
41		
42		
43	TOTAL	33,772,360

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	430,772,609	430,772,609		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	24,289,967	24,289,967		
4	(403.1) Depreciation Expense for Asset Retirement Costs	7,566	7,566		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,261,165	1,261,165		
7	Other Clearing Accounts	111,437	111,437		
8	Other Accounts (Specify, details in footnote):	775,309	775,309		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	26,445,444	26,445,444		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	11,423,683	11,423,683		
13	Cost of Removal	3,558,245	3,558,245		
14	Salvage (Credit)	1,832,794	1,832,794		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	13,149,134	13,149,134		
16	Other Debit or Cr. Items (Describe, details in footnote):	-540,400	-540,400		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	443,528,519	443,528,519		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	187,742,365	187,742,365		
21	Nuclear Production				
22	Hydraulic Production-Conventional	1,777,683	1,777,683		
23	Hydraulic Production-Pumped Storage				
24	Other Production	12,193,364	12,193,364		
25	Transmission	78,196,657	78,196,657		
26	Distribution	135,691,945	135,691,945		
27	Regional Transmission and Market Operation				
28	General	27,926,505	27,926,505		
29	TOTAL (Enter Total of lines 20 thru 28)	443,528,519	443,528,519		

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.: 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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	Otter Tail Energy Services Company			
2	Capital Stock			10
3	Additional paid in capital			4,452,294
4	Earnings (loss) since acquisition			-4,200,203
5				
6	Equity in subsidiary earnings			
7				
8				
9	Varistar			
10	Additional Paid in Capital			129,034,882
11	Advance (open stock)			36,398,524
12	Earnings (Loss) since acquisition			134,620,780
13				
14	Equity in subsidiary earnings			
15				
16				
17	Otter Tail Assurance			
18	Additional Paid in Capital			1,479,922
19	Earnings (Loss) since acquisition			-486,756
20				
21	Equity in subsidiary earnings			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 155,273,831		TOTAL	301,299,453

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		10		2
		4,452,294		3
		-4,266,382		4
				5
-66,179				6
				7
				8
				9
		149,335,360		10
		34,720,516		11
		159,880,411		12
				13
32,215,659				14
				15
				16
				17
		1,486,167		18
		575,145		19
				20
1,061,901				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
33,211,381		346,183,521		42

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) _ A Resubmission	/ /	2007/Q4

FOOTNOTE DATA

Schedule Page: 224 Line No.: 12 Column: g

Includes the following 2007 changes, in addition to 2007 earnings:

	2006	2007
Distribution to parent:	($6,777,121)	($6,956,028)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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)	7,467,638	8,798,580	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)	3,601,522	3,855,189	Production
8	Transmission Plant (Estimated)	3,232,776	3,569,715	Various
9	Distribution Plant (Estimated)	5,274,528	6,078,164	Various
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	292,693	271,969	Fleet Service
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	12,401,519	13,775,037	
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)	19,869,157	22,573,617	

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2007/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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2008 No. (d)	2008 Amt. (e)
1	Balance-Beginning of Year	29,000.00		16,276.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	12,695.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	16,305.00		16,276.00	
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		203.41	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	203.41			
40	Balance-End of Year			203.41	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	203.41	90,402		
45	Gains	203.41	90,402		
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.

2009		2010		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
16,276.00		14,054.00		365,404.00		441,010.00		1
								2
								3
				14,054.00		14,054.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						12,695.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
16,276.00		14,054.00		379,458.00		442,369.00		29
								30
								31
								32
								33
								34
								35
203.41		202.97		9,945.30		10,758.50		36
				405.93		405.93		37
								38
				202.96		406.37		39
203.41		202.97		10,148.27		10,758.06		40
								41
								42
								43
				202.96	39,248	406.37	129,650	44
				202.96	39,248	406.37	129,650	45
								46

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						
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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
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						
48						
49	TOTAL					

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	Big Stone II Delivery Service	49,119	417.1	59,634	417
3	Big Stone II Delivery Facility	7,919	417.1	11,335	417
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21	**Generation Studies**				
22	Big Stone II Generator Inter	87,770	417.1	116,059	417
23	Veblen/Hillhead Wind Farm Inter	5,923	417.1	9,275	417
24	Elbow Lake (Roseville) Wind Farm	72	417.1	79	417
25	MISO Coordinated Group	6,977	417.1	5,428	417
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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 $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Income Tax Adjustments					
2	Due to SFAS109 on:					
3	Property Related Items	11,372,375		282	2,945,721	8,426,654
4	Non Property Related Items	339,518	12,858	190	46,216	306,160
5						
6						
7	Asset Retirement Obligation Capitalized					
8	Hoot Lake Plant	157,855	45,927			203,782
9	Big Stone Plant	7,329	3,959			11,288
10	Coyote Station	84,168	45,777			129,945
11						
12	Derivatives-Marked to Market Losses		3,386,502	244	2,615,790	770,712
13						
14	Regulatory Assets: MISO Costs Deferred	541,426	315,896	555	2,772	854,550
15	Regulatory Assets: MISO Refund		576,284	555	503	575,781
16						
17	SFAS 158 - Postretirement Medical Benefits	3,924,640	202,540	228.3	3,602,816	524,364
18						
19	Regluatory Assets - ESSRP	6,292,271		228	1,016,641	5,275,630
20						
21	Regulator Assets - Pension	26,518,959		228	5,386,067	21,132,892
22						
23						
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44	TOTAL	49,238,541	4,589,743		15,616,526	38,211,758

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 $50,000, 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	1,035,609	2,074,085	908	2,618,980	490,714
3	Energy Efficiency					
4	Program - SD		27,488			27,488
5	Deferred Cost - Big Stone					
6	Plant Jurisdiction					
7	(Amort. period 22-1/2 years)					
8	North Dakota	138,974		406	40,675	98,299
9	South Dakota	12,552		406	3,675	8,877
10						
11						
12						
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	1,187,135				625,378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	159,117	155,997
4	Medical Insurance Reserve		
5	Injuries and Damages Reserve	144,540	147,830
6	See Note Below	38,609,659	54,248,027
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	38,913,316	54,551,854
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)	38,913,316	54,551,854

Notes

NOTE: Continued From Above

Post Retirement Medical Benefits	12,534,804	13,436,690
Executive Supplemental Pension	6,147,344	6,770,086
Reserve for Bad Debts	220,521	229,568
Accrued Vacation Pay	1,229,503	1,257,804
Capitalized Int. on Construction	1,782,717	2,314,613
Post Employment Benefits	1,133,522	1,121,752
Corporate Insurance Reserve	(24,415)	(69,784)
Nonqualified Retirement Savings	3,628,698	4,009,438
Deferred Settlement	58,337	25,526
Gain From Breck Sale	231,087	231,087
Reserve for Loan Pools	89,478	89,707
Gain on Reacquired Bonds	92	47
Capitalized A & G	4,730,571	5,186,812
Customer Rebates Capitalized	35,964	44,207
Asbestos Removal Costs Capitalized	15,582	13,218
Stock Incentives	301,012	320,318
Stock Options	73,199	11,378
Mapleton Land	41,803	27,982
CIAC Capitalized	330,608	305,815
Big Stone II Land	23,539	23,539
Otter Tail Assurance, LTD Gains/Losses	(11,969)	(14,467)
MN PUC Refund	0	0
Medicare Part D	126,423	174,974
Executive Stock Incentive Plan	785,003	1,211,897
Affordable Housing	202,083	293,545
Wind Energy Income Tax Credits-ND	0	12,988,625
SFAS 109 Unamortized ITC	5,231,699	4,504,984
SFAS 109 Recognition of Regulatory Assets (Liab.)	(307,546)	(261,334)
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	38,609,659	54,248,027

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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 Over the Counter	50,000,000	5.00	
3	(National Market System)			
4				
5	TOTAL_COMMON	50,000,000		
6				
7	Account 204 (Stated Value)			
8	Cumulative Preferred	1,500,000		
9	$3.60 Dividend - No Exchange		100.00	102.25
10	$4.40 Dividend - No Exchange		100.00	102.00
11	$4.65 Dividend - No Exchange		100.00	101.50
12	$6.75 Dividend - No Exchange		100.00	102.03
13	Preference Shares	1,000,000		
14				
15	TOTAL_PREFERRED	2,500,000		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
29,849,789	149,248,945					2
						3
						4
29,849,789	149,248,945					5
						6
						7
						8
60,000	6,000,000					9
25,000	2,500,000					10
30,000	3,000,000					11
40,000	4,000,000					12
						13
						14
155,000	15,500,000					15
						16
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	Tax benefit from stock options.	3,200,462
2	Executive stock incentive plan performance award.	3,107,436
3	Employee stock purchase plan expense	127,800
4	Stock option expense	361,872
5	Restricted stock units	463,250
6		
7		
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40	TOTAL	7,260,820

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	3,336,780
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13	Cumulative Preferred Shares	86,017
14	$6.75 Series	
15		
16		
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21		
22	TOTAL	3,422,797

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	768,252
3	2012 Variable Series Pollution Control	10,400,000	142,703
4	2017 Series Pollution Control Refund-BSP	5,185,000	266,331
5	2022 Series Pollution Control Refund-CYT	20,790,000	1,112,076
6	Senior Unsecured Notes 6.47%, Series D	50,000,000	318,018
7	Issued 08/20/07 & 10/01/07 MN Public Utilities Commission Authorization		
8	Docket No. E-017/S-07-364 dated 09/17/07		
9	Senior Unsecured Notes 6.37%, Series C	42,000,000	267,151
10	Issued 08/20/07 & 10/01/07 MN Public Utilities Commission Authorization		
11	Docket No. E-017/S-07-364 dated 09/17/07		
12	Senior Unsecured Notes 6.15%, Series B	30,000,000	190,752
13	Issued 10/01/07 MN Public Utilities Commission Authorization		
14	Docket No. E-017/S-07-364 dated 09/17/07		
15	Senior Unsecured Notes 5.95%, Series A	33,000,000	209,876
16	Issued 10/01/07 MN Public Utilities Commission Authorization		
17	Docket No. E-017/S-07-364 dated 09/17/07		
18	Senior Unsecured Notes 5.778%	50,000,000	346,723
19	Issued 12/14/07 MN Public Utilities Commission Authorization		
20	Docket No. E-017/S-07-364 dated 09/17/07		
21	Account 222 - Reacquired Bonds - None		
22	Account 224 - Other Long - Term Debt		
23	Lombard US Equipment Finance	16,300,000	81,500
24			
25	Instruction 15 - Interest expense on obligations retired in 2007:		
26	2007 Series 6.375% Senior Debentures, retired 12/01/07		
27	2032 Series - Uninsured Senior Note 6.80%, retired 10/15/07		
28	2017 Series - Insured Senior Note 5.625%, retired 10/15/07		
29			
30	Instruction 9 - See Footnote		
31	Instruction 15 - See Footnote		
32			
33	TOTAL	347,675,000	3,703,382

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
12/27/01	12/01/11	01/01/02	12/01/11	90,000,000	5,967,000	2
12/15/93	12/01/12	12/01/93	12/01/12	10,400,000	400,362	3
09/26/01	09/01/17	10/01/01	09/01/17	5,185,000	241,103	4
09/26/01	09/01/22	10/01/01	09/01/22	20,705,000	1,005,163	5
08/20/07 &	08/20/37	08/20/07	08/20/37	50,000,000	902,206	6
10/01/07						7
						8
08/20/07 &	08/20/27	08/20/07	08/20/27	42,000,000	753,783	9
10/01/07						10
						11
10/01/07	08/20/22	10/01/07	08/20/22	30,000,000	461,250	12
						13
						14
10/01/07	08/20/17	10/01/07	08/20/17	33,000,000	490,875	15
						16
						17
12/14/07	11/30/17	12/14/07	11/30/17	50,000,000	144,450	18
						19
						20
						21
						22
09/24/03	10/02/10	09/30/03	09/30/10	6,985,712	531,263	23
						24
						25
					2,919,522	26
					1,341,111	27
					1,775,000	28
						29
						30
						31
						32
				338,275,712	16,933,088	33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	/ /	2007/Q4

FOOTNOTE DATA

Schedule Page: 256 Line No.: 23 Column: a

Principal repaid during the year was $2,328,572.

Schedule Page: 256 Line No.: 30 Column: a

Instruction 9 - Unamortized debt expense, premium and discount are adjusted annually to reflect debt retired through sinking fund operations. Unamortized debt expense remaining on bonds retired early are transferred to Account 189 and amortized over remaining life of the bonds.

Schedule Page: 256 Line No.: 31 Column: a

Instruction 15 - Interest on notes payable to associated companies in account 233 was $1,590,735 charged to account 430.

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)	53,960,704
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Interest Capitalized on Construction	1,714,223
6	Net Gain from Property Retirements	-1,479,784
7	Miscellaneous Taxable Items	9,000
8	Conservation Improvement Program - MN	544,894
9	Deductions Recorded on Books Not Deducted for Return	
10	Add Back Federal Income Taxes (Includes Deferreds & ITC Adj.)	10,490,977
11	Provision for Reserves	11,914,823
12	Miscellaneous Unallowed Deductions	11,225,266
13		
14	Income Recorded on Books Not Included in Return	
15	Tax Exempt Interest	22,878
16	Equity in Earnings of Subsidiaries	33,211,381
17	(None)	
18	Miscellaneous Income Not Taxable	3,524,918
19	Deductions on Return Not Charged Against Book Income	
20	Excess Tax Depreciation Over Book Depreciation	2,682,696
21	Removal Costs	3,949,203
22	Charges to Reserves	7,666,252
23	Capital Loss Carry Forward	
24	Leveraged ESOP Deduction	1,879,028
25	Early Bond Redemption	1,375,206
26	Miscellaneous other Deductions	5,236,372
27	Federal Tax Net Income	28,832,169
28	Show Computation of Tax:	
29	Federal Tax (LINE 27 X 35%)	10,091,259
30	Tax (Credits) and Adjustments	436,473
31	Prior Period Adjustments	-2,759,077
32		
33	Total Federal Income Tax	7,768,655
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	See Footnote	
44		

Name of Respondent Otter Tail Corporation	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2007/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 43 Column: a

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

Otter Tail Corporation is a member of an affiliated group which will file a consolidatd Federal Income Tax Return for the year 2007. The other members of the affiliated group and their respective federal income tax provisions are as follows:

1	Varistar Corporation	(1,390,913)
2	DMI Industries, Inc.	4,167,538
3	Aerial Contractors, Inc.	976,816
4	Moorhead Electric, Inc.	347,961
5	DMS Health Technologies, Inc.	100,359
6	DMS Imaging, Inc.	761,857
7	BTD Manufacturing, Inc.	1,824,374
8	Northern Pipe Products, Inc.	1,210,599
9	Otter Tail Energy Services Company	(69,737)
10	E. W. Wylie Corporation	533,742
11	Vinyltech Corporation	2,379,698
12	T. O. Plastics, Inc.	716,246
13	ShoreMaster, Inc.	289,541
14	Galva Foam Marine Industries, Inc.	1,260,201
15	Otter Tail Assurance Limited	366,148
16	Midwest Construction Services, Inc.	8,258
17	Overland Mechanical Services, Inc.	18,660
18	AC Equipment, Inc.	6,533
19	Foley Company	1,256,080
20	Lynk3 Technologies, Inc.	(71,424)
21	Ventus Energy Systems, Inc.	(869,575)
22	Idaho-Pacific Corporation	677,156
23	Idaho-Pacific Colorado Corporation	1,457,552
24	Shoreline Industries, Inc.	(6,515)
25	Aviva Sports, Inc.	(312,777)
	Total	15,638,378

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL					
2	Income	3,241,746		22,408,216	22,749,998	
3	Unemployment	935		51,720	51,628	
4	FICA	-10,430		4,360,117	4,349,686	
5						
6	MINNESOTA					
7	Property	4,860,999		4,747,005	4,703,005	
8	Income	749,564		1,699,018	1,644,602	
9	Unemployment	2,476		82,480	82,557	
10						
11	NORTH DAKOTA					
12	Property	2,731,776		2,398,929	2,798,158	
13	Income	527,272		-684,944	537,395	
14	Unemployment	1,014		28,631	29,057	
15	Foreign Corporation					
16	Coal Conversion	188,975		753,852	755,341	
17						
18	SOUTH DAKOTA					
19	Property	1,647,001		1,554,989	1,601,989	
20	Unemployment					
21	Foreign Corporation					
22						
23	OTHER STATES					
24	Income	-35,141		724,912	999,768	
25	Railcar	41,207		95,843	94,081	
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	13,947,394		38,220,768	40,397,265	

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
2,899,964		8,105,663		-1,137,043	15,439,596	2
1,027					51,720	3
1					4,360,117	4
						5
						6
4,904,999		4,747,005				7
803,980		1,224,337			474,681	8
2,399					82,480	9
						10
						11
2,332,547		2,355,761			43,168	12
-695,067		-1,505,884			820,940	13
588					28,631	14
						15
187,486		753,852				16
						17
						18
1,600,001		1,554,989				19
						20
						21
						22
						23
-309,997					724,912	24
42,969					95,843	25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
11,770,897		17,235,723		-1,137,043	22,122,088	41

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

Account 409.2 $87,022; Account 409.2 ($244,961); Account 123.1 $16,054,210; Account 228.4 ($456,675)

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 ($130,162) Account 123.1 $604,843

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

Account 184

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

Account 408.2 $1,850; Account 921 $41,318

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

Account 409.2 ($60,725); Account 123.1 $881,665

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

Account 184

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

Account 408.2

Schedule Page: 262 Line No.: 24 Column: l

Account 409.2 ($268,126); Account 123.1 $993,038

Schedule Page: 262 Line No.: 25 Column: l

Account 151

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year 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%		190	9,750,000	411.4	32,500	
3	4%	22,593			411.4	22,593	
4	7%						
5	10%	8,158,068				1,114,063	
6							
7							
8	TOTAL	8,180,661		9,750,000		1,169,156	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
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47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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
9,717,500	25 yrs		2
	33 1/3 yrs		3
			4
7,044,005	33 1/3 yrs		5
			6
			7
16,761,505			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
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			46
			47
			48

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2007/Q4

FOOTNOTE DATA

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

Account 411.4 was allocated $1,113,390 and Account 411.5 was allocated $673.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, 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	110,419	456	22,807	83,827	171,439
2						
3						
4	Asset Retirement Obligation					
5	Accrual					
6	Hoot Lake Plant	3,434,879	254	3,446,059	11,180	
7	Big Stone Plant	6,308,802	254	6,316,704	7,902	
8	Coyote Station	3,349,115	254	3,354,973	5,858	
9						
10						
11						
12						
13						
14						
15						
16						
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18						
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44						
45						
46						
47	TOTAL	13,203,215		13,140,543	108,767	171,439

Name of Respondent Otter Tail Corporation	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2007/Q4

FOOTNOTE DATA

Schedule Page: 269 Line No.: 6 Column: a

The asset retirement obligations for Hoot Lake Plant, Big Stone Plant, and Coyote Station were reclassified to account 254 in the 1st quarter of 2007.

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 Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/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
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							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	116,055,244	10,798,514	4,672,354
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	116,055,244	10,798,514	4,672,354
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	116,055,244	10,798,514	4,672,354
10	Classification of TOTAL			
11	Federal Income Tax	95,997,074	8,932,076	3,846,395
12	State Income Tax	20,058,170	1,866,438	825,959
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
536,331	126,754	182.3	2,945,721	190	3,412,500	123,057,760	2
							3
							4
536,331	126,754		2,945,721		3,412,500	123,057,760	5
							6
							7
							8
536,331	126,754		2,945,721		3,412,500	123,057,760	9
							10
451,068	103,873		2,477,427		3,412,500	102,365,023	11
85,263	22,881		468,294			20,692,737	12
							13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	/ /	2007/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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	1,703,182	1,560,000	1,871,046
5				
6	Accum. Deferred Income Tax			
7	Nonutility & Other	305,722		
8				
9	TOTAL Electric (Total of lines 3 thru 8)	2,008,904	1,560,000	1,871,046
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)	2,008,904	1,560,000	1,871,046
20	Classification of TOTAL			
21	Federal Income Tax	1,678,625	1,312,000	1,572,487
22	State Income Tax	330,279	248,000	298,559
23	Local Income Tax			

NOTES

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/Q4

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	10,137,584	228.3	10,190,959	1,445,511	4
							5
							6
2,284,727	1,242,824					1,347,625	7
							8
2,284,727	1,242,824		10,137,584		10,190,959	2,793,136	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
2,284,727	1,242,824		10,137,584		10,190,959	2,793,136	19
							20
563,575	1,044,000		8,525,968		8,570,858	982,603	21
1,721,152	198,824		1,611,616		1,620,101	1,810,533	22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2007/Q4

FOOTNOTE DATA

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

Credits to Accounts 219 - $225,070; and 182.3 - $9,802,984; and 228.4 - $109,530

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

Adjustments due to SFAS 109.

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

Deferred taxes related to CIP costs and mark-to-market accounting, which are considered non-utility.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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 $50,000 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	5,228,395	190	908,286	181,571	4,501,680
2	SFAS 109					
3						
4						
5	Minnesota Portion of Gain on Sale of Wahpeton	150,560	407.4	5,576		144,984
6	Division Office (Amortization period: 34 years)					
7						
8						
9	Regulatory Liabilities - Derivatives		175	171,376	442,248	270,872
10						
11	Hoot Lake Plant - Asset Retirement Obligation		108	333,575	3,498,143	3,164,568
12						
13	Big Stone Plant - Asset Retirement Obligation		108	169,719	6,296,236	6,126,517
14						
15	Coyote Station - Asset Retirement Obligation		108	316,716	3,343,117	3,026,401
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	5,378,955		1,905,248	13,761,315	17,235,022

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	/ /	2007/Q4

FOOTNOTE DATA

Schedule Page: 278 Line No.: 8 Column: a

The asset retirement obligations for Hoot Lake Plant, Big Stone Plant, and Coyote Station were reclassified from account 253 in the 1st quarter of 2007.

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/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.

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	92,254,111	86,949,503
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	105,786,364	101,824,083
5	Large (or Ind.) (See Instr. 4)	74,821,602	65,441,194
6	(444) Public Street and Highway Lighting	2,868,359	2,877,902
7	(445) Other Sales to Public Authorities	2,461,466	2,379,775
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	278,191,902	259,472,457
11	(447) Sales for Resale	20,345,040	23,129,699
12	TOTAL Sales of Electricity	298,536,942	282,602,156
13	(Less) (449.1) Provision for Rate Refunds	1,297,930	-1,453,772
14	TOTAL Revenues Net of Prov. for Refunds	297,239,012	284,055,928
15	Other Operating Revenues		
16	(450) Forfeited Discounts	545,326	547,329
17	(451) Miscellaneous Service Revenues	349,770	345,778
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	635,191	671,788
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	10,701,451	10,080,525
22	(456.1) Revenues from Transmission of Electricity of Others	433,024	310,770
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	12,664,762	11,956,190
27	TOTAL Electric Operating Revenues	309,903,774	296,012,118

ELECTRIC OPERATING REVENUES (Account 400)

5. 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.)
6. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
7. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
8. 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
1,218,026	1,170,841	101,704	101,417	2
				3
1,518,825	1,452,713	26,422	26,277	4
1,318,059	1,298,238	51	52	5
27,078	26,818	406	406	6
41,843	42,244	592	574	7
				8
				9
4,123,831	3,990,854	129,175	128,726	10
3,543,401	3,175,314			11
7,667,232	7,166,168	129,175	128,726	12
				13
7,667,232	7,166,168	129,175	128,726	14

Line 12, column (b) includes $ 8,404,303 of unbilled revenues.
Line 12, column (d) includes 5,797 MWH relating to unbilled revenues

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) _ A Resubmission	/ /	2007/Q4

FOOTNOTE DATA

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

Small (or Commercial) includes all customers having a demand of less that 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.: 10 Column: b

2007 unbilled revenue included in this report is: System Total 5,797 mwh and $8,404,303; MN 3,312 mwh and $2,801,657; ND 4,191 mwh and $4,571,573; SD (1,706) mwh and $1,031,073.

2006 unbilled revenue included in this report is: System Total 3,085 mwh and $1,074,673; MN 708 mwh and $949,496; ND 1,872 mwh and ($75,859); SD 505 mwh and $201,036.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Not applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	850,049	71,585,414	94,355	9,009	0.0842
4						
5	Residential Service (Ctrl Demand)					
6	R-03	161,018	9,616,822	6,583	24,460	0.0597
7						
8	Water Heating (Controlled)					
9	R-91	49,481	2,830,286	18,997	2,605	0.0572
10				-18,997		
11	Controlled Service					
12	I-01,02,03	145,705	5,174,361	9,138	15,945	0.0355
13				-9,138		
14	Fixed Time of Delivery Service					
15	I-04	1,545	51,632	142	10,880	0.0334
16				-142		
17	Outdoor lighting-energy only					
18	M-41	53	3,573	4	13,250	0.0674
19				-4		
20	Area, Flood & Sign Lighting					
21	M-42	4,237	456,203	5,414	783	0.1077
22				-5,414		
23	Small power producer rider					
24	P-01		9			
25						
26	SUBTOTAL Billed	1,212,088	89,718,300	100,938	12,008	0.0740
27	Unbilled Rev (See Instr. 6)	5,938	2,535,811			0.4270
28	TOTAL - 440	1,218,026	92,254,111	100,938	12,067	0.0757
29						
30	Column D Lines 9,12,15,18 & 21					
31	Customers are also served under					
32	other residential service.					
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,118,034	269,787,599	129,349	31,837	0.0655
42	Total Unbilled Rev.(See Instr. 6)	5,797	8,404,303	0	0	1.4498
43	TOTAL	4,123,831	278,191,902	129,349	31,881	0.0675

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/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	Commercial & Industrial-442					
2	General Service					
3	G-01	749,702	62,575,872	23,328	32,137	0.0835
4						
5	General Service (Ctrl Demand)					
6	G-02	7,118	455,845	61	116,689	0.0640
7				-18		
8	Electric Climate Control					
9	G-93	50,665	3,499,910	596	85,008	0.0691
10				-107		
11	Farm Service					
12	F-61	60,311	4,136,943	2,759	21,860	0.0686
13						
14	Large Commercial Service					
15	C-02	1,150,465	66,946,711	560	2,054,402	0.0582
16						
17	Large Com. Srv. (Real Time Pricin					
18	C-03	58,656	2,916,796	1	58,656,000	0.0497
19				-1		
20	Large Gen. Srv. (Off Peak Rider)					
21	C-04	30,236	1,726,393	8	3,779,500	0.0571
22						
23	Large Gen. Srv. (Time of Use)					
24	C-09	417,994	20,769,167	18	23,221,889	0.0497
25				-18		
26	Large Gen. Srv. (Time of Use)					
27	C-11	11,396	456,992	1	11,396,000	0.0401
28				-1		
29	Large general service rider					
30	C-12	52,548	1,785,127	6	8,758,000	0.0340
31				-6		
32	Water heating (controlled)					
33	R-91	2,259	126,458	648	3,486	0.0560
34				-648		
35						
36						
37						
38	Column D Lines 6,9,18,24,27,30&33					
39	Customers are also served under					
40	other commercial service.					
41	TOTAL Billed	4,118,034	269,787,599	129,349	31,837	0.0655
42	Total Unbilled Rev.(See Instr. 6)	5,797	8,404,303	0	0	1.4498
43	TOTAL	4,123,831	278,191,902	129,349	31,881	0.0675

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	Commercial & Industrial, Cont.					
2	Controlled service					
3	I-01, 02, 03	173,214	5,042,587	3,413	50,751	0.0291
4				-3,413		
5	Fixed time of delivery service					
6	I-04	12,547	355,089	330	38,021	0.0283
7				-330		
8	Bulk interruptible service					
9	I-06	9,574	390,816	1	9,574,000	0.0408
10				-1		
11	Irrigation service					
12	M-03	6,423	384,056	212	30,297	0.0598
13				-212		
14	Commercial time of use					
15	M-04	24,836	1,357,838	127	195,559	0.0547
16						
17	Outdoor lighting-energy only					
18	M-41	458	31,747	39	11,744	0.0693
19				-39		
20	Area, flood, and sign lighting					
21	M-42	15,700	1,632,279	6,577	2,387	0.1040
22				-6,577		
23	Standby service					
24	P-13	121	21,570	3	40,333	0.1783
25				-3		
26	Residential service					
27	R-01	242	17,607	10	24,200	0.0728
28						
29	Residential service (ctrl demand)					
30	R-03	2,615	145,794	79	33,101	0.0558
31						
32	Small power producer rider					
33	P-01		42	3		
34				-3		
35	Column D, lines 3,6,9,12,18,21,					
36	24 & 33					
37	customers are also served under					
38	other commerical service.					
39						
40						
41	TOTAL Billed	4,118,034	269,787,599	129,349	31,837	0.0655
42	Total Unbilled Rev.(See Instr. 6)	5,797	8,404,303	0	0	1.4498
43	TOTAL	4,123,831	278,191,902	129,349	31,881	0.0675

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/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	Commercial and industrial - conti					
2	Small power producer rider					
3	P-09	-3	16	1	-3,000	-0.0053
4				-1		
5	SUBTOTAL Billed	2,837,077	174,775,655	27,403	103,532	0.0616
6	Unbilled Rev (See Instr. 6)	-193	5,832,311			-30.2192
7	TOTAL - 442	2,836,884	180,607,966	27,403	103,525	0.0637
8						
9	Miscellaneous					
10	Streetlighting - 444					
11	Outdoor lighting-energy only					
12	M-41	3,932	262,430	151	26,040	0.0667
13				-151		
14	Area, flood, and sign lighting					
15	M-42	23,191	2,630,747	405	57,262	0.1134
16	Subtotal billed	27,123	2,893,177	405	66,970	0.1067
17	Unbilled Revenue	-45	-24,818			0.5515
18	TOTAL - 444	27,078	2,868,359	405	66,859	0.1059
19						
20	Other Public Authority-445	41,746	2,400,467	603	69,231	0.0575
21	Unbilled Rev (See Instr. 6)	97	60,999			0.6289
22	TOTAL - 445	41,843	2,461,466	603	69,391	0.0588
23						
24	Revenue from Fuel Adjustment					
25	Clause is reported in footnote.					
26						
27	Column D, Lines 3 & 12					
28	Customers are also served under					
29	other commercial service.					
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	4,118,034	269,787,599	129,349	31,837	0.0655
42	Total Unbilled Rev.(See Instr. 6)	5,797	8,404,303	0	0	1.4498
43	TOTAL	4,123,831	278,191,902	129,349	31,881	0.0675

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	/ /	2007/Q4

FOOTNOTE DATA

Schedule Page: 304.3 Line No.: 24 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	$ 9,454,761
R-03 Residential service (control demand)	1,841,150
R-91 Water heating (controlled)	588,316
I-03 Controlled service	107,179
M-41 Outdoor lighting - energy only	319
Total residential	11,991,725
Commercial and industrial - 442	
G-01 General service	8,353,145
G-02 General service (control demand)	88,003
G-93 Electric climate control	624,278
F-61 Farm service	591,830
C-02 Large commercial service	12,640,555
C-03 Large commercial service (real-time pricing)	281,928
C-04 Large general service (off-peak rider)	313,403
C-09 Large general service (time of use)	3,993,294
C-11 Large general service (time of use)	61,282
C-12 Large general service rider	405,882
I-03 Controlled service	206,148
M-03 Irrigation service	66,795
M-04 Commercial time of use	238,208
M-41 Outdoor lighting - energy only	3,422
M-42 Area, flood, and sign lighting	5
Total commercial and industrial	27,868,178
Miscellaneous	
Streetlighting - 444	
M-41 Outdoor lighting - energy only	20,989
Other pubic authority - 445	479,652
Total miscellaneous	500,641
Total	$ 40,360,544

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	RQ SALES					
2	Badger, SD	RQ	144	98	N/A	N/A
3	Newfolden, MN	RQ	174	505	N/A	N/A
4	Nielsville, MN	RQ	175	44	N/A	N/A
5	Shelly, MN	RQ	176	192	N/A	N/A
6						
7						
8	NON-RQ SALES					
9	American Electric Power Service	OS	180	N/A	N/A	N/A
10	Associated Electric Cooperative Inc	OS	180	N/A	N/A	N/A
11	Black Hills Power and Light	OS	180	N/A	N/A	N/A
12	BP Corporation North America Inc	OS	180	N/A	N/A	N/A
13	Cargill Power Markets, LLC	OS	180	N/A	N/A	N/A
14	Constellation Engy Commodities Grp Inc	OS	180	N/A	N/A	N/A
	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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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.
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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	Actual Demand (MW) Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	DTE Energy Trading, Inc.	OS	180	N/A	N/A	N/A
2	Fortis Energy Marketing and Trading	OS	180	N/A	N/A	N/A
3	Great River Energy	OS	180	N/A	N/A	N/A
4	High Sierra Power Marketing LLC	OS	180	N/A	N/A	N/A
5	Integrys Energy Services Inc	OS	180	N/A	N/A	N/A
6	Kansas City Power and Light	OS	180	N/A	N/A	N/A
7	Lighthouse Energy Trading Company	OS	180	N/A	N/A	N/A
8	Lincoln Electric System	OS	180	N/A	N/A	N/A
9	Manitoba Hydro Electric Board	OS	180	N/A	N/A	N/A
10	Mid-American Energy Company	OS	180	N/A	N/A	N/A
11	Minnesota Municipal Power Agency	OS	180	N/A	N/A	N/A
12	Minnesota Power	OS	180	N/A	N/A	N/A
13	Minnkota Power Cooperative	OS	180	N/A	N/A	N/A
14	Missouri River Energy Services	OS	180	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/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:
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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 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	Northern States Power Company	OS	180	N/A	N/A	N/A
2	NorthPoint Energy Solutions Inc.	OS	180	N/A	N/A	N/A
3	Omaha Public Power District	OS	180	N/A	N/A	N/A
4	Rainbow Energy Marketing Copr	OS	180	N/A	N/A	N/A
5	Sempra Energy Trading Corporation	OS	180	N/A	N/A	N/A
6	Split Rock Energy	OS	180	N/A	N/A	N/A
7	The Energy Authority	OS	180	N/A	N/A	N/A
8	Transalta Energy Marketing	OS	180	N/A	N/A	N/A
9	Utilities Plus	OS	180	N/A	N/A	N/A
10	Western Area Power Administration	OS	180	N/A	N/A	N/A
11	Western Resources	OS	180	N/A	N/A	N/A
12	UBS Securities LLC	OS	180	N/A	N/A	N/A
13	RBC Capital Markets Corporation	OS	180	N/A	N/A	N/A
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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	Midwest ISO Automatic Reserve Sharing	OS	180	N/A	N/A	N/A
2	Midwest ISO Energy Market	OS	180	N/A	N/A	N/A
3	Non-asset based sales	OS	180	N/A	N/A	N/A
4						
5						
6						
7						
8						
9						
10						
11						
12	See Footnote					
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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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
357	5,302	12,202	3,497	21,001	2
2,339	28,388	79,941	23,489	131,818	3
123	3,048	4,191	1,265	8,504	4
829	13,578	28,323	8,207	50,108	5
					6
					7
					8
72,800		5,107,840		5,107,840	9
85,600		1,393,165		1,393,165	10
13,367		781,459		781,459	11
7,200		37,107		37,107	12
59,777		2,383,566		2,383,566	13
306,600		300,589		300,589	14
3,648	50,316	124,657	36,458	211,431	
3,539,753	0	20,133,609	0	20,133,609	
3,543,401	**50,316**	**20,258,266**	**36,458**	**20,345,040**	

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.
186,640		-566,830		-566,830	1
8,800		53,017		53,017	2
24,000		19,490		19,490	3
118,800		-231,388		-231,388	4
131,200		436,685		436,685	5
1,600		48,000		48,000	6
9,054		480,321		480,321	7
6,835		291,920		291,920	8
77,600		2,857,536		2,857,536	9
800		13,600		13,600	10
18,800		1,123,937		1,123,937	11
60,789		3,976,465		3,976,465	12
91,813		4,994,499		4,994,499	13
18,758		1,262,092		1,262,092	14
3,648	50,316	124,657	36,458	211,431	
3,539,753	0	20,133,609	0	20,133,609	
3,543,401	**50,316**	**20,258,266**	**36,458**	**20,345,040**	

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/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.
491,200		6,745,700		6,745,700	1
5,725		322,150		322,150	2
3,863		165,536		165,536	3
61,337		2,987,087		2,987,087	4
149,400		10,399,675		10,399,675	5
5,600		-7,994		-7,994	6
19,680		1,105,896		1,105,896	7
28,800		76,375		76,375	8
5,338		335,208		335,208	9
97,485		5,046,741		5,046,741	10
57,574		547,124		547,124	11
516,400		17,206		17,206	12
182,100		-389,557		-389,557	13
					14
3,648	50,316	124,657	36,458	211,431	
3,539,753	0	20,133,609	0	20,133,609	
3,543,401	**50,316**	**20,258,266**	**36,458**	**20,345,040**	

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.
		56,077		56,077	1
1,001,313		30,177,288		30,177,288	2
-386,895		-62,213,973		-62,213,973	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
3,648	50,316	124,657	36,458	211,431	
3,539,753	0	20,133,609	0	20,133,609	
3,543,401	**50,316**	**20,258,266**	**36,458**	**20,345,040**	

Name of Respondent Otter Tail Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2007/Q4

FOOTNOTE DATA

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

Line 2 through 5 are fuel adjustment charges.

Schedule Page: 310.3 Line No.: 3 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: 310.3 Line No.: 12 Column: a

MAPP Transmission Service Charges for Non-RQ sales is $25,173.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	1,394,608	1,237,058
5	(501) Fuel	55,008,518	55,407,546
6	(502) Steam Expenses	3,191,009	2,845,667
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,260,200	2,167,452
10	(506) Miscellaneous Steam Power Expenses	4,140,261	3,620,701
11	(507) Rents	3,216	533
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	65,997,812	65,278,957
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	695,172	693,886
16	(511) Maintenance of Structures	605,164	547,646
17	(512) Maintenance of Boiler Plant	5,918,965	6,794,804
18	(513) Maintenance of Electric Plant	687,113	1,304,483
19	(514) Maintenance of Miscellaneous Steam Plant	800,370	823,310
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	8,706,784	10,164,129
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	74,704,596	75,443,086
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	65,688	11,206
45	(536) Water for Power		
46	(537) Hydraulic Expenses	6,565	
47	(538) Electric Expenses	52,478	55,772
48	(539) Miscellaneous Hydraulic Power Generation Expenses	3,558	1,687
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	128,289	68,665
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	280	
54	(542) Maintenance of Structures	4,846	2,423
55	(543) Maintenance of Reservoirs, Dams, and Waterways	417,502	166,228
56	(544) Maintenance of Electric Plant	39,688	6,727
57	(545) Maintenance of Miscellaneous Hydraulic Plant	18,991	
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	481,307	175,378
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	609,596	244,043

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	37,444	61,881
63	(547) Fuel	6,236,150	4,241,702
64	(548) Generation Expenses	622,259	408,965
65	(549) Miscellaneous Other Power Generation Expenses	68,914	81,408
66	(550) Rents	3,647	5,909
67	TOTAL Operation (Enter Total of lines 62 thru 66)	6,968,414	4,799,865
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	48,987	42,741
70	(552) Maintenance of Structures	3,337	13,295
71	(553) Maintenance of Generating and Electric Plant	1,191,492	1,457,479
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	12,313	18,136
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,256,129	1,531,651
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	8,224,543	6,331,516
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	74,694,689	58,281,221
77	(556) System Control and Load Dispatching	259,924	1,320,525
78	(557) Other Expenses	1,847,801	1,189,337
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	76,802,414	60,791,083
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	160,341,149	142,809,728
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	511,139	897,785
84	(561) Load Dispatching		821,405
85	(561.1) Load Dispatch-Reliability	48,028	36,123
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,398,686	1,951,981
87	(561.3) Load Dispatch-Transmission Service and Scheduling	19,089	11,045
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	325,934	192,519
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	160,433	128,295
94	(563) Overhead Lines Expenses	540,237	443,430
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	10,283	
97	(566) Miscellaneous Transmission Expenses	1,018,264	1,114,496
98	(567) Rents	40,143	51,709
99	TOTAL Operation (Enter Total of lines 83 thru 98)	5,072,236	5,648,788
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	403,322	446,059
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	7,601	5,985
104	(569.2) Maintenance of Computer Software	561,311	294,063
105	(569.3) Maintenance of Communication Equipment	183,405	140,156
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,143,012	1,003,874
108	(571) Maintenance of Overhead Lines	1,630,625	1,606,049
109	(572) Maintenance of Underground Lines	308	115
110	(573) Maintenance of Miscellaneous Transmission Plant		24,596
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,929,584	3,520,897
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	9,001,820	9,169,685

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation	1,173,754	761,112
117	(575.3) Transmission Rights Market Facilitation	261,333	83,878
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)	1,435,087	844,990
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software	56,085	38,100
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)	56,085	38,100
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	1,491,172	883,090
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	522,846	561,423
135	(581) Load Dispatching	295,848	102,288
136	(582) Station Expenses	145,438	134,832
137	(583) Overhead Line Expenses	330,930	204,846
138	(584) Underground Line Expenses	1,099,905	895,226
139	(585) Street Lighting and Signal System Expenses		
140	(586) Meter Expenses	1,000,585	888,276
141	(587) Customer Installations Expenses	327,862	437,625
142	(588) Miscellaneous Expenses	2,274,823	2,218,456
143	(589) Rents	240,965	195,338
144	TOTAL Operation (Enter Total of lines 134 thru 143)	6,239,202	5,638,310
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	813,410	842,551
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	832,021	781,149
149	(593) Maintenance of Overhead Lines	4,537,893	3,564,321
150	(594) Maintenance of Underground Lines	829,638	852,334
151	(595) Maintenance of Line Transformers		
152	(596) Maintenance of Street Lighting and Signal Systems	992,747	928,523
153	(597) Maintenance of Meters	441,438	380,034
154	(598) Maintenance of Miscellaneous Distribution Plant		
155	TOTAL Maintenance (Total of lines 146 thru 154)	8,447,147	7,348,912
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	14,686,349	12,987,222
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	192,629	164,940
160	(902) Meter Reading Expenses	4,569,617	4,264,482
161	(903) Customer Records and Collection Expenses	4,713,170	4,235,640
162	(904) Uncollectible Accounts	684,000	679,000
163	(905) Miscellaneous Customer Accounts Expenses	347,844	337,562
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	10,507,260	9,681,624

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	727,164	668,145
168	(908) Customer Assistance Expenses	4,106,516	3,896,708
169	(909) Informational and Instructional Expenses	327,300	463,255
170	(910) Miscellaneous Customer Service and Informational Expenses	80,719	74,299
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	5,241,699	5,102,407
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	803,691	692,564
176	(913) Advertising Expenses	299,288	321,170
177	(916) Miscellaneous Sales Expenses	318,260	307,222
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	1,421,239	1,320,956
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	16,602,139	15,326,870
182	(921) Office Supplies and Expenses	4,649,145	3,453,847
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	1,595,302	2,075,081
185	(924) Property Insurance	974,518	2,079,320
186	(925) Injuries and Damages	1,646,497	492,380
187	(926) Employee Pensions and Benefits	914,010	4,325,074
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	1,931,771	832,892
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	615,095	561,159
192	(930.2) Miscellaneous General Expenses	680,508	891,522
193	(931) Rents	295,752	351,344
194	TOTAL Operation (Enter Total of lines 181 thru 193)	29,904,737	30,389,489
195	Maintenance		
196	(935) Maintenance of General Plant	2,724,986	3,168,234
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	32,629,723	33,557,723
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	235,320,411	215,512,435

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

$1,001,213 of the year-to-date expense recorded in accounts 561 and 569 is designated as acocunt 561.BA expense.

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

$971,751 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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	American Electric Power Service	OS		N/A	N/A	N/A
2	BP Corporation North America Inc	OS		N/A	N/A	N/A
3	Black Hills Power and Light	OS		N/A	N/A	N/A
4	Cargill Power Markets, LLC	OS		N/A	N/A	N/A
5	Constellation Energy Commodities Group	OS		N/A	N/A	N/A
6	DTE Energy Trading, Inc.	OS		N/A	N/A	N/A
7	Fortis Energy Marketing and Trading	OS		N/A	N/A	N/A
8	Great River Energy	OS		N/A	N/A	N/A
9	Great River Energy	SF		50	N/A	N/A
10	High Sierra Power Marketing, LLC	OS		N/A	N/A	N/A
11	Integrys Energy Services Inc	OS		N/A	N/A	N/A
12	Lighthouse Energy Trading Company, Inc	OS		N/A	N/A	N/A
13	Manitoba Hydro Electric Board	SF		50	N/A	N/A
14	Manitoba Hydro Electric Board	OS		N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Mid-American Energy Company	OS		N/A	N/A	N/A
2	Minnesota Municipal Power Agency	OS		N/A	N/A	N/A
3	Minnesota Power	OS		N/A	N/A	N/A
4	Minnkota Power Cooperative	OS		N/A	N/A	N/A
5	Missouri River Energy Services	OS		N/A	N/A	N/A
6	Northern States Power Company	OS		N/A	N/A	N/A
7	Northern States Power Company	SF		75	N/A	N/A
8	NorthPoint Energy Solutions Inc	OS		N/A	N/A	N/A
9	Omaha Public Power District	OS		N/A	N/A	N/A
10	Rainbow Energy Marketing Corp.	OS		N/A	N/A	N/A
11	Sempra Energy Trading Corporation	OS		N/A	N/A	N/A
12	Split Rock Energy	OS		N/A	N/A	N/A
13	The Energy Authority	OS		N/A	N/A	N/A
14	Transalta Energy Marketing	OS		N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Western Area Power Administration	OS		N/A	N/A	N/A
2	Western Area Power Administration-WEC	OS		N/A	N/A	N/A
3	Western Resources	OS		N/A	N/A	N/A
4	Wisconsin Public Power Inc	SF		50	N/A	N/A
5	Beltrami Electric Cooperative	RQ		N/A	N/A	N/A
6	Nodak Rural Electric Cooperative	RQ		N/A	N/A	N/A
7	PKM Electric Cooperative	RQ		N/A	N/A	N/A
8	NorthWestern Energy - NLE	RQ		N/A	N/A	N/A
9	Red Lake Rural Electric Cooperative	RQ		N/A	N/A	N/A
10	City of Perham	RQ		N/A	N/A	N/A
11	Lac Qui Parle School	RQ		N/A	N/A	N/A
12	Dakota Magic Casino	RQ		N/A	N/A	N/A
13	State Auto Insurance	RQ		N/A	N/A	N/A
14	Kindred School	RQ		N/A	N/A	N/A
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Fleet Farm	RQ		N/A	N/A	N/A
2	Valley Queen Cheese	OS		N/A	N/A	N/A
3	Stevens Community Medical	OS		N/A	N/A	N/A
4	City of Detroit Lakes	OS		N/A	N/A	N/A
5	American Crystal Sugar	OS		N/A	N/A	N/A
6	Energy Maintenance Service	OS		N/A	N/A	N/A
7	Hendricks Wind 1	OS		N/A	N/A	N/A
8	Borderline Wind	OS		N/A	N/A	N/A
9	Univ. of MN - Morris	OS		N/A	N/A	N/A
10	FPL Energy ND Wind II, LLC	OS		N/A	N/A	N/A
11	Langdon Wind, LLC	OS		N/A	N/A	N/A
12	MN Co Generation	OS		N/A	N/A	N/A
13	ABN AMRO Inc / USB Securities LLC	OS		N/A	N/A	N/A
14	RBC Capital Markets Corporation	OS		N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	NorthWestern Energy Load Error	OS		N/A	N/A	N/A
2	MISO Transmission Service Charge	OS		N/A	N/A	N/A
3	MAPP Transmission Service Charge	OS		N/A	N/A	N/A
4	WAPA Schedule and Dispatch	OS		N/A	N/A	N/A
5	Midwest ISO Energy market	OS		N/A	N/A	N/A
6	Control Area Exchange - Net	OS		N/A	N/A	N/A
7	Non-asset based cost of sales					
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a 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)	
800				52,200		52,200	1
1,600				11,778		11,778	2
1,220				88,880		88,880	3
48,855				3,247,650	2,592	3,250,242	4
386,400				-887,922		-887,922	5
155,000				-488,462		-488,462	6
14,400				117,398		117,398	7
48,800				64,498		64,498	8
			253,750			253,750	9
148,450				318,418		318,418	10
130,400				820,370		820,370	11
6,378				400,787		400,787	12
			1,602,800			1,602,800	13
407,226				20,241,191	-837,247	19,403,944	14
4,469,999			3,818,763	71,089,487	-213,561	74,694,689	

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)	
208,322				9,875,211		9,875,211	1
400				38,800		38,800	2
6,400				406,704		406,704	3
20,258				319,433		319,433	4
16,036				566,328		566,328	5
307,030				1,878,004		1,878,004	6
			149,000			149,000	7
19,260				1,122,638		1,122,638	8
22,433				981,588	1,315	982,903	9
13,129				703,305		703,305	10
20,000				1,240,402		1,240,402	11
8,400				-15,788		-15,788	12
19,600				904,160		904,160	13
38,400				-64,268		-64,268	14
4,469,999			3,818,763	71,089,487	-213,561	74,694,689	

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)	
16,923				667,101	20,022	687,123	1
29,870				583,668		583,668	2
9,600				111,185		111,185	3
			207,500			207,500	4
89,328			1,085,491	3,336,945	124,967	4,547,403	5
3,457			39,814	166,648		206,462	6
3,310			39,978	132,907		172,885	7
17,540			143,795	742,173		885,968	8
313			14,007	13,856		27,863	9
			31,052			31,052	10
19				456		456	11
			35,832			35,832	12
			36,000			36,000	13
			35,460			35,460	14
4,469,999			3,818,763	71,089,487	-213,561	74,694,689	

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)	
			17,944			17,944	1
			104,710			104,710	2
			20,520			20,520	3
877			1,110	1,349		2,459	4
146				1,462		1,462	5
199				6,376		6,376	6
2,801				126,058		126,058	7
2,411				64,991		64,991	8
1,454				69,084		69,084	9
62,760				1,876,532		1,876,532	10
1,970				77,264		77,264	11
11				708		708	12
1,242,300				2,758,543		2,758,543	13
126,900				-160,832		-160,832	14
4,469,999			3,818,763	71,089,487	-213,561	74,694,689	

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)	
-14,455				-553,869		-553,869	1
					178,656	178,656	2
					272,582	272,582	3
					23,552	23,552	4
1,558,640				77,940,563		77,940,563	5
				-1,532,363		-1,532,363	6
-735,572				-57,284,621		-57,284,621	7
							8
							9
							10
							11
							12
							13
							14
4,469,999			3,818,763	71,089,487	-213,561	74,694,689	

Name of Respondent Otter Tail Corporation	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2007/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 4 Column: l
Cargill Power Market LLC transmission.

Schedule Page: 326 Line No.: 9 Column: a
Winter season through April 30, 2008.

Schedule Page: 326 Line No.: 13 Column: a
Winter season through April 30, 2008.

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

Schedule Page: 326.1 Line No.: 7 Column: a
Winter season through April 30, 2008.

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

Schedule Page: 326.2 Line No.: 1 Column: l
Load Following charge.

Schedule Page: 326.2 Line No.: 4 Column: a
Winter season through April 30, 2008.

Schedule Page: 326.2 Line No.: 5 Column: l
Nomination charge.

Schedule Page: 326.4 Line No.: 2 Column: l
Transmission service charge.

Schedule Page: 326.4 Line No.: 3 Column: l
Transmission service charge.

Schedule Page: 326.4 Line No.: 4 Column: l
Scheduling/dispatch charge.

Schedule Page: 326.4 Line No.: 5 Column: a
Midwest ISO Energy Market

Schedule Page: 326.4 Line No.: 6 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.: 7 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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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 Classifi-cation (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	Fergus Falls Regional Treatment Center	Western Area Power Administration	Fergus Falls, MN	LFP
12	Oakes O&M Headquarters	Western Area Power Administration	Oakes, ND	LFP
13	Minnkota Power Cooperative, Inc.	Minnkota Power Cooperative, Inc.	Various Interconnects	LFP
14		U.S. Bureau of Reclamation	Otter Tail Power Company	OS
15		Various Companies	Otter Tail Power Company	OS
16		Various Companies	Otter Tail Power Company	OS
17	See Footnote			
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions 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		1,390	1,330	1
4	(1)	Newfolden, MN		3,022	2,824	2
4	(1)	Nielsville, MN		677	633	3
4	(1)	Shelly, MN		1,800	1,682	4
4	(1)	Fort Totten, ND		248	234	5
4	(1)	Grafton, ND		5,034	4,749	6
4	(1)	Devils Lake, ND		608	568	7
4	(1)	Bottineau, ND		1,173	1,096	8
4	(1)	Wahpeton, ND		8,782	8,246	9
4	(1)	Belcourt, ND		2,572	2,426	10
4	(1)	Fergus Falls, MN		1,180	1,113	11
4	(1)	Oakes, ND		42	40	12
See Footnote	(1)	Various Interconnecs		206,356	192,856	13
		(1)		-10,541		14
		(1)		-96,373		15
		(1)		17,764		16
	See Footnote					17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**143,734**	**217,797**	

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.
9,519			9,519	1
25,915			25,915	2
8,014			8,014	3
17,297			17,297	4
1,668			1,668	5
25,011			25,011	6
5,956			5,956	7
11,034			11,034	8
92,259			92,259	9
34,374			34,374	10
8,065			8,065	11
1,056			1,056	12
	192,856		192,856	13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
240,168	**192,856**	**0**	**433,024**	

Name of Respondent Otter Tail Corporation	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2007/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 13 Column: e

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

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

Various companies
Miscellaneous losses - mwh received

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

Lines 1 - 11 Otter Tail Power Company wheels WAPA's portion of customers' load.
Line 12 Otter Tail Power Company wheels WAPA's total load to customer.
Line 13 Otter tail Power Company wheels MPC's total load to various interconnects.
Lines 14 - 16 contain losses and regulation that result from interconnects with various companies in the integrated system.

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

(1) Various points of interconnect in the integrated system in column f, lines 1-13 and column g, lines 14-16.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	Kansas City Pwr & Light	NF		100			23	23
2	Lincoln Electric System	NF		150			40	40
3	Mid-American Energy Co.	NF		9			1	1
4	Missouri Public Service	NF		50			11	11
5	Nebraska Public Pwr	NF		100			6	6
6	Omaha Public Pwr Dist	NF		125			36	36
7	Otter Tail Power Co.	FNS					8,471	8,471
8	Saskatchewan Pwr Co.	NF		50			6	6
9	Western Area Pwr Admin	SFP		100			48	48
10	Western Area Pwr Admin	NF		4,225			1,641	1,641
11								
12								
13								
14								
15								
16								
	TOTAL			4,909			10,283	10,283

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
	(1) X An Original	(Mo, Da, Yr)	
Otter Tail Corporation	(2) __ A Resubmission	/ /	2007/Q4

FOOTNOTE DATA

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

Charges in lines 1 through 10 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 2007.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	67,383
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	57,757
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	197,491
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	38,786
6	Director Fees and Expenses	166,407
7	Miscellaneous labor not provided for elsewhere	152,684
8		
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45		
46	TOTAL	680,508

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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			458,713		458,713
2	Steam Production Plant	7,969,874	7,566			7,977,440
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	84,546				84,546
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	1,068,206				1,068,206
7	Transmission Plant	3,946,009				3,946,009
8	Distribution Plant	8,775,975				8,775,975
9	Regional Transmission and Market Operation					
10	General Plant	2,445,357				2,445,357
11	Common Plant-Electric					
12	TOTAL	24,289,967	7,566	458,713		24,756,246

B. Basis for Amortization Charges

The $458,713 is amortization of:

Miscellaneous Intangible Plant (303)
$410,801 for computer software with a five-year average service life at a 20% rate.

Franchises and Consents (302)
$47,912 for hydro plant licenses with a remaining life of 13.54 years at a 3.68% rate.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production-						
13	Big Stone Plant						
14	311	5,311		-3.70	1.98	SQ	14.22
15	312	23,359		-3.70	2.71	SQ	14.23
16	314	9,708		-3.70	3.20	SQ	14.23
17	315	2,528		-3.70	2.36	SQ	14.22
18	316	1,013		-3.50	2.99	SQ	14.23
19							
20	Steam Production						
21	Hoot Lake Plant						
22	311 - Units 2,3	205		-9.90	1.20	SQ	11.32
23	312 - Units 2,3	7,351		-9.90	3.36	SQ	11.33
24	314 - Units 2,3	2,032		-9.90	2.57	SQ	11.33
25	315 - Units 2,3	57		-9.90	1.12	SQ	11.32
26	316 - Units 2,3	282		9.70	3.93	SQ	11.33
27							
28	Steam Production						
29	Coyote Plant						
30	311	12,068		-1.70	2.11	SQ	19.00
31	312	37,712		-1.70	2.38	SQ	19.00
32	314	8,495		-1.70	2.55	SQ	19.00
33	315	3,187		-1.70	2.06	SQ	18.99
34	316	860		-1.40	2.72	SQ	19.01
35	STEAM PRODUCTION						
36	SUBTOTAL	114,168					
37							
38	Hydro Production -						
39	Hoot Lake Hydro						
40	331	7			0.62	SQ	15.18
41	332	27			0.72	SQ	15.17
42	333	-1			-0.04	SQ	15.19
43	334	10			1.94	SQ	15.20
44	Hydro Production -						
45	Wright Hydro						
46	331	7			2.59	SQ	15.18
47	332	39			1.32	SQ	15.17
48	333	174			5.00	SQ	15.19
49	334	159			5.70	SQ	15.20
50	335	18			2.14	SQ	15.19

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			2.01	SQ	15.18
16	332	21			1.25	SQ	15.17
17	333	181			7.48	SQ	15.19
18	334	82			4.85	SQ	15.20
19	335	9			2.71	SQ	15.19
20							
21	Hydro Production -						
22	Dayton Hollow Hydro						
23	331				0.82	SQ	15.18
24	332	66			1.50	SQ	15.17
25	333	-11			-2.52	SQ	15.19
26	334	80			3.93	SQ	15.20
27	335	4			3.10	SQ	15.19
28							
29	Hydro Production -						
30	Taplin Gorge Hydro						
31	331	3			0.48	SQ	15.18
32	332	99			1.78	SQ	15.17
33	333	-6			-2.56	SQ	15.19
34	334				0.02	SQ	15.20
35	335	37			3.87	SQ	15.19
36							
37	Hydro Production -						
38	Bemidji Hydro						
39	331	29			4.18	SQ	15.18
40	332	53			1.74	SQ	15.17
41	333	202			4.90	SQ	15.19
42	334	-2			-1.66	SQ	15.20
43	335	1			6.16	SQ	15.19
44	HYDRO PRODUCTION						
45	SUBTOTAL	1,292					
46							
47							
48							
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	Other Production -						
13	Jamestown Peaking #1						
14	341	71			2.32	SQ	13.26
15	342	56			2.05	SQ	13.26
16	343	671			1.99	SQ	13.26
17	345	5			1.56	SQ	13.25
18	346	12			2.40	SQ	13.26
19							
20	Other Production -						
21	Lake Preston Peaking						
22	341	47			1.82	SQ	13.26
23	342	73			1.83	SQ	13.26
24	343	890			2.12	SQ	13.26
25	345	69			1.86	SQ	13.26
26	346	7			2.15	SQ	13.26
27							
28	Other Production -						
29	Jamestown Peaking #2						
30	341	8			4.26	SQ	13.27
31	342	14			2.87	SQ	13.26
32	343	1,241			2.46	SQ	13.26
33	345	17			3.17	SQ	13.26
34	346	9			2.40	SQ	13.26
35							
36	Other Production -						
37	Fergus Falls Control Cr						
38	343	410			2.92	SQ	23.73
39	Other Production -						
40	Solway Combustion Turb						
41	341	3,667			3.21	SQ	31.17
42	342	893			3.21	SQ	31.17
43	343	18,562			2.84	SQ	31.17
44	345	1,103			3.21	SQ	31.17
45	346	276			3.21	SQ	31.18
46							
47	OTHER PRODUCTION						
48	SUBTOTAL	28,101					
49							
50							

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Transmission Plant						
13	353	34,052	45.00	-5.00	2.14	R1.5	31.61
14	354	2,303	55.00	-10.00	1.98	R5	29.90
15	355	36,981	55.00	-25.00	2.17	S1.5	37.22
16	356	41,344	55.00	-10.00	1.93	S1.5	38.94
17	358	19	40.00	-5.00	2.61	S4	12.28
18	SUBTOTAL	114,699					
19							
20	Distribution Plant -						
21	362	28,507	35.00	5.00	2.50	S-.5	24.72
22	364	28,714	60.00	-50.00	2.44	R3	42.96
23	365	23,482	58.00	-40.00	2.37	R2.5	40.73
24	366	5	50.00		1.75	R4	28.85
25	367	28,247	35.00	-5.00	2.80	R3	22.45
26	368	27,005	40.00	-5.00	2.41	R4	24.75
27	369	1,951	48.00	-100.00	4.12	S6	28.84
28	369.1	15,216	40.00	-30.00	3.17	R4	27.73
29	370	13,290	33.00		2.93	L1	23.36
30	370.1	7,158	20.00		5.51	R4	16.10
31	370.2	484	9.00		11.11	Amortized	
32	371		25.00		0.74	R3	2.88
33	371.2	2,377	19.00	10.00	4.40	L1	12.83
34	373	1,798	16.00	-5.00	5.63	L2	8.89
35	SUBTOTAL	178,234					
36							
37	General Plant -						
38	390	13,588	45.00	10.00	2.17	L1	32.86
39	390.1	3,857		-0.20	4.89	SQ	14.23
40	390.2	492		-0.20	4.40	SQ	14.22
41	390.3	2,620		-0.30	2.86	SQ	23.70
42	391	1,043	15.00		6.67	Amortized	
43	391.1	374	10.00		10.00	Amortized	
44	391.2	650	10.00		10.00	Amortized	
45	391.5	400	5.00		20.00	Amortized	
46	391.6	677	5.00		20.00	Amortized	
47	392	11,560					
48	Aircraft		7.00	39.00			
49	Autos		5.00	15.00			
50	Light Trucks		10.00	10.00			

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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	Heavy Trucks & Semi		10.00	15.00			
13	Tractors (Includes		10.00	15.00			
14	Cranes)						
15	Trailers		15.00	10.00			
16	Portable Oil Purifier		10.00	20.00			
17	Trenchers		10.00	10.00			
18	Misc. Light Equip.		10.00	10.00			
19	Misc. Heavy Equip.		15.00	15.00			
20	393		15.00		6.67	Amortized	
21	394	1,183	15.00		6.67	Amortized	
22	394.2	151	15.00		6.67	Amortized	
23	395	68	15.00		6.67	Amortized	
24	396	310	15.00	20.00	6.99	S2	6.07
25	397	179	15.00		6.67	Amortized	
26	397.1	449	10.00		10.00	Amortized	
27	397.2	1,595	15.00		6.67	Amortized	
28	397.3	92	10.00		10.00	Amortized	
29	397.4	794	25.00	5.00	6.60	S5	8.77
30	SUBTOTAL	40,082					
31	TOTAL	476,576					
32							
33	SUBACCOUNTS USED						
34							
35							
36							
37							
38							
39							
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Name of Respondent Otter Tail Corporation	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2007/Q4

FOOTNOTE DATA

Schedule Page: 336.4 Line No.: 33 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.

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1					
2	Regulatory Agency Assessments:				
3	MN Dept. of Commerce/Public Util. Commission	139,670		139,670	
4	SD Public Utilities Commission	34,475		34,475	
5	Federal Energy Regulatory Commission	229,142		229,142	
6					
7	Other Expenses:				
8	MN Public Utilities Commission:				
9	E017/M-04-1751 (Ethics Hotline)	37,334	3,080	40,414	
10	E017/RP-05-968(2006 2020 Resource Plan)	24,452	1,495	25,947	
11	MN Rate Case (Matter 28659.000002)		951,783	951,783	
12	Miscellaneous	94,669	155,836	250,505	
13					
14	ND Public Service Commission:				
15	ND PSC case No. PU-07-3 (TOD rate)		39,168	39,168	
16	Miscellaneous	1,391	56,144	57,535	
17					
18	SD Public Utilities Commission:				
19	Miscellaneous		7,388	7,388	
20					
21	Federal Assesment	230		230	
22					
23	FERC				
24	ER04-691-065 (MISO RSG)		88,412	88,412	
25	Miscellaneous		67,102	67,102	
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	561,363	1,370,408	1,931,771	

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
							2
Electric	928	139,670					3
Electric	928	34,475					4
Electric	928	229,142					5
							6
							7
							8
Electric	928	40,414					9
Electric	928	25,947					10
Electric	928	951,783					11
Electric	928	250,505					12
							13
							14
Electric	928	39,168					15
Electric	928	57,535					16
							17
							18
Electric	928	7,388					19
							20
Electric	928	230					21
							22
							23
Electric	928	88,412					24
Electric	928	67,102					25
							26
							27
							28
							29
							30
							31
							32
							33
							34
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		1,931,771					46

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Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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 $5,000.)
- (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		
5	Other	2 Minor Miscellaneous Projects
6		
7		
8		
9	Sub-Total Performed Internally	
10		
11	PERFORMED EXTERNALLY:	
12		E-Source General Research
13		Chartwell, Inc.
14		
15	Other	1 Minor Miscellaneous Project
16		
17	Sub-Total Performed Externally	
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37	SUM OF ABOVE	
38		

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/Q4

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 $5,000 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 $5,000 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
					4
6,761		930.2	6,761		5
					6
					7
					8
6,761			6,761		9
					10
					11
	42,960	930.2	42,960		12
	7,871	930.2	7,871		13
					14
	165	930.2	165		15
					16
	50,996		50,996		17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
6,761	50,996		57,757		37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	8,904,066		
4	Transmission	3,619,526		
5	Regional Market	1,432,283		
6	Distribution	5,044,763		
7	Customer Accounts	7,247,999		
8	Customer Service and Informational	1,673,304		
9	Sales	822,117		
10	Administrative and General	17,823,993		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	46,568,051		
12	Maintenance			
13	Production	4,538,899		
14	Transmission	2,087,081		
15	Regional Market	31,208		
16	Distribution	5,093,503		
17	Administrative and General	1,771,627		
18	TOTAL Maintenance (Total of lines 13 thru 17)	13,522,318		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	13,442,965		
21	Transmission (Enter Total of lines 4 and 14)	5,706,607		
22	Regional Market (Enter Total of Lines 5 and 15)	1,463,491		
23	Distribution (Enter Total of lines 6 and 16)	10,138,266		
24	Customer Accounts (Transcribe from line 7)	7,247,999		
25	Customer Service and Informational (Transcribe from line 8)	1,673,304		
26	Sales (Transcribe from line 9)	822,117		
27	Administrative and General (Enter Total of lines 10 and 17)	19,595,620		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	60,090,369		60,090,369
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	60,090,369		60,090,369
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	9,230,786		9,230,786
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	9,230,786		9,230,786
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,019,061		2,019,061
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,019,061		2,019,061
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock (151)	35,751		35,751
79	Miscellaneous Deferred Debits (186)	449,825		449,825
80	Other Electric Revenue (456)	375,086		375,086
81	Expenses of Nonutility Operations (417.1)	1,161,698		1,161,698
82	Miscellaneous Nonoperating Income (421)	10,121,744		10,121,744
83	Exp for Certain Civic, Political and Related Activity (426.4)	93,469		93,469
84	Other Deductions (426.5)	39,124		39,124
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	12,276,697		12,276,697
96	TOTAL SALARIES AND WAGES	83,616,913		83,616,913

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	/ /	2007/Q4

FOOTNOTE DATA

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8	Not currently available.				
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
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34					
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36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

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

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

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

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

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

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

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	81,445	$/MW-Hr	12,551	7,113,741	$/MW-Hr	667,967
2	Reactive Supply and Voltage	211,220	$/MW-Hr	31,683	4,123,471	$/MW-Hr	616,700
3	Regulation and Frequency Response	28,201	$/MW-Hr	20,022	4,337,352	$/MW-Hr	454,554
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other				41,726	$/MW-Hr	4,373
8	Total (Lines 1 thru 7)	320,866		64,256	15,616,290		1,743,594

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

Line 1, Scheduling, System Control and Dispatch does not include $23,552 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.

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	675	11	900	674	1				
2	February	681	3	1000	680	1				
3	March	642	5	900	641	1				
4	Total for Quarter 1	1,998			1,995	3				
5	April	607	4	900	606	1				
6	May	488	29	1200	486	2				
7	June	599	25	1700	597	2				
8	Total for Quarter 2	1,694			1,689	5				
9	July	638	23	1700	636	2				
10	August	591	9	1600	590	1				
11	September	565	5	1600	563	2				
12	Total for Quarter 3	1,794			1,789	5				
13	October	555	24	900	553	2				
14	November	658	29	1700	657	1				
15	December	681	5	1700	680	1				
16	Total for Quarter 4	1,894			1,890	4				
17	Total Year to Date/Year	7,380			7,363	17				

Schedule Page: 400 Line No.: 1 Column: b

Due to meter data corrections, the monthly peak MW for January 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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:

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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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)	4,123,831
3	Steam	3,298,499			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	3,648
5	Hydro-Conventional	20,371			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,539,753
7	Other	59,420			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	27
9	Net Generation (Enter Total of lines 3 through 8)	3,378,290	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	12,015
10	Purchases	4,469,999	27	Total Energy Losses	94,952
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	7,774,226
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	143,734			
17	Delivered	217,797			
18	Net Transmission for Other (Line 16 minus line 17)	-74,063			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	7,774,226			

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 on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

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	632,062	204,741		0	
30	February	542,744	132,737		0	
31	March	430,588	36,880		0	
32	April	417,731	74,057		0	
33	May	611,975	395,099		0	
34	June	678,711	407,727		0	
35	July	763,689	440,320		0	
36	August	825,962	523,621		0	
37	September	659,795	370,856		0	
38	October	612,772	338,450		0	
39	November	667,075	203,488		0	
40	December	931,122	411,777		0	
41	TOTAL	7,774,226	3,539,753			

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	/ /	2007/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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	7862			7030		
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			73		
12	Net Generation, Exclusive of Plant Use - KWh	1032449239			1318470541		
13	Cost of Plant: Land and Land Rights	718662			374603		
14	Structures and Improvements	31545992			21789382		
15	Equipment Costs	115316670			112667881		
16	Asset Retirement Costs	142263			13691		
17	Total Cost	147723587			134845557		
18	Cost per KW of Installed Capacity (line 17/5) Including	1019.4865			604.2821		
19	Production Expenses: Oper, Supv, & Engr	497203			468305		
20	Fuel	13116446			22035039		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	1894413			561112		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	551236			735115		
26	Misc Steam (or Nuclear) Power Expenses	502966			1974485		
27	Rents	506			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	210789			278900		
30	Maintenance of Structures	140374			270081		
31	Maintenance of Boiler (or reactor) Plant	1566048			2454698		
32	Maintenance of Electric Plant	271277			297391		
33	Maintenance of Misc Steam (or Nuclear) Plant	230728			274758		
34	Total Production Expenses	18981986			29349884		
35	Expenses per Net KWh	0.0184			0.0223		
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	845379	6560	0	812849	3348	5551
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	6896	140000	0	8531	140000	15000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	14.710	97.820	0.000	26.770	103.660	20.000
41	Average Cost of Fuel per Unit Burned	14.670	94.210	0.000	26.400	94.210	20.000
42	Average Cost of Fuel Burned per Million BTU	1.064	16.021	0.000	1.547	16.021	0.667
43	Average Cost of Fuel Burned per KWh Net Gen	0.013	0.000	0.000	0.017	0.000	0.000
44	Average BTU per KWh Net Generation	11362.000	0.000	0.000	10687.000	0.000	0.000

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

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

Line No.	Item (a)	Plant Name: *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			44.50		
6	Net Peak Demand on Plant - MW (60 minutes)	27			46		
7	Plant Hours Connected to Load	127			2216		
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	1129440			53833680		
13	Cost of Plant: Land and Land Rights	12339			89809		
14	Structures and Improvements	194155			4171571		
15	Equipment Costs	3770010			23437644		
16	Asset Retirement Costs	0			0		
17	Total Cost	3976504			27699024		
18	Cost per KW of Installed Capacity (line 17/5) Including	165.0002			622.4500		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	375093			4550998		
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	21597			540189		
26	Misc Steam (or Nuclear) Power Expenses	5172			59264		
27	Rents	100			2708		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			2158		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	31112			705190		
33	Maintenance of Misc Steam (or Nuclear) Plant	771			11953		
34	Total Production Expenses	433845			5872460		
35	Expenses per Net KWh	0.3841			0.1091		
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	4031	0	0	641808	269	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	140000	0	0	638592	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	92.400	0.000	0.000	7.060	0.000	0.000
41	Average Cost of Fuel per Unit Burned	93.070	0.000	0.000	7.060	80.890	0.000
42	Average Cost of Fuel Burned per Million BTU	15.829	0.000	0.000	7.055	13.757	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.332	0.000	0.000	0.085	0.000	0.000
44	Average BTU per KWh Net Generation	20986.000	0.000	0.000	11951.000	0.000	0.000

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Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	119.50	48.11	5
0	144	56	6
0	17171	473	7
0	0	0	8
0	144	42	9
0	0	42	10
0	48	1	11
0	955328400	4268020	12
0	150121	24614	13
0	5701405	244250	14
0	40635949	6710405	15
0	129451	0	16
0	46616926	6979269	17
0.0000	390.0998	145.0690	18
0	308447	0	19
0	19777436	1310059	20
0	0	0	21
0	752916	0	22
0	0	0	23
0	0	0	24
0	973848	55689	25
0	1192664	4054	26
0	2710	939	27
0	0	0	28
0	212039	0	29
0	194709	1080	30
0	1898219	0	31
0	118602	449940	32
0	292545	2490	33
0	25724135	1824251	34
0.0000	0.0269	0.4274	35

(d)			(e)			(f)			Line No.
RRM			Coal	Oil		Oil			36
Tons			Tons	Barrels		Barrels			37
416	0	0	590079	1008	0	14517	0	0	38
7187	0	0	9175	140000	0	140000	0	0	39
8.500	0.000	0.000	33.010	100.720	0.000	90.300	0.000	0.000	40
8.500	0.000	0.000	32.560	95.970	0.000	90.260	0.000	0.000	41
0.591	0.000	0.000	1.774	16.321	0.000	15.350	0.000	0.000	42
0.000	0.000	0.000	0.021	0.000	0.000	0.307	0.000	0.000	43
0.000	0.000	0.000	11343.000	0.000	0.000	19999.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Otter Tail Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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

									Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Otter Tail Corporation	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) / /	2007/Q4

FOOTNOTE DATA

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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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
			4
			5
			6
			7
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			10
			11
			12
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GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydro:					
2	Hoot Lake	1914	1.00	0.8	1,821,269	562,931
3	Wright	1922	0.40	0.5	2,462,271	686,302
4	Pisgah	1917	0.52	0.7	3,893,796	416,504
5	Dayton Hollow	1909	0.97	1.0	7,571,983	619,803
6	Taplin Gorge	1925	0.56	0.6	3,671,468	639,176
7	Bemidji	-	0.74	0.8	949,756	567,329
8						
9	Internal Combustion:					
10	Fergus Control Center	1995	1.83	2.1	21,948	591,638
11	Diesel Generators		2.26	1.7		
12						
13						
14						
15						
16						
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45						
46						

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
714,379	6,082		76,118	-		2
1,406,357	5,369		46,485	-		3
578,478	10,474		46,636	-		4
606,461	12,514		193,675	-		5
1,131,285	5,142		40,328	-		6
751,429	74,534		76,617	-		7
						8
						9
286,369	4,810		5,250	Oil		10
				Oil		11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
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						37
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						42
						43
						44
						45
						46

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

Various.

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	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)	Winnepeg	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	Underwood	230.00	230.00	Wood H	72.00		1
16	Underwood	Coal Creek	230.00	230.00	Wood H	3.00		1
17	Harvey	Rugby	230.00	230.00	Steel H	40.00		1
18								
19								
20								
21								
22		Total	115.00	115.00	Wood H	449.00		
23		Total	115.00	115.00	SWP	350.00		
24		Total	69.00	69.00		216.00		
25								
26								
27								
28								
29								
30		Total	41.60	41.60	SWP	3,791.00		
31		Total	41.60	41.60	Underground	1.00		
32								
33								
34								
35								
36					TOTAL	5,259.00		15

Name of Respondent Otter Tail Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) 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
		593,550	593,550					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
								21
	74,783	5,941,485	6,016,268					22
	49,282	11,938,591	11,987,873					23
		5,953,449	5,953,449					24
								25
								26
								27
								28
								29
	4,953	79,707,925	79,712,878					30
		53,066	53,066					31
								32
								33
								34
				4,843,197	1,837,637	40,143	6,720,977	35
	141,292	135,773,248	135,914,540	4,843,197	1,837,637	40,143	6,720,977	36

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 Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/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	Brooks Enbridge Jct.	Brooks Enbridge Sub	0.65	Single pole	18.00	1	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							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		0.65		18.00	1	1

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
10RT2	ACSR	3102 vert	41		53,149	97,375		150,524	1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
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									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
					53,149	97,375		150,524	44

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Bemidji, MN	Transmission	115.00	69.00	13.80
2			41.60	2.40	
3			15.70	2.40	
4	Big Stone, SD Highway 12	Transmission	115.00	41.60	
5	Big Stone, SD Plant	Transmission	22.90	230.00	13.80
6			230.00	115.00	
7			23.60	13.80	
8			115.00	12.50	
9	Browns Valley, MN	Transmission	230.00	41.60	
10			41.60	4.16	
11	Buffalo, ND	Transmission	345.00	115.00	43.00
12			41.60	2.40	
13			41.60	2.40	
14	Canby, MN	Transmission	115.00	41.60	
15			41.60	4.16	
16	Cass Lake, MN	Transmission	115.00	41.60	
17	Clearbrook, MN	Transmisison	115.00	41.60	
18			115.00	41.60	
19			41.60	13.80	
20	Crookston, MN	Transmission	115.00	41.60	
21			115.00	41.60	
22			41.90	2.30	
23	Center, ND	Transmission	345.00	230.00	13.80
24	Devils Lake, ND	Transmission	115.00	41.60	
25			41.60	2.40	
26	Devils Lake, ND	Transmission	115.00	41.60	
27	Donaldson, MN	Transmission	115.00	41.60	
28			115.00	41.60	
29			41.60	2.40	
30	Fergus Falls, MN Edgetown	Transmission	115.00	12.50	
31	Fertile, MN	Transmission	115.00	41.60	
32			41.60	2.30	
33	Finley, ND	Transmission	115.00	41.60	
34			41.60	2.40	
35			41.60	2.40	
36	Forman, ND	Transmission	230.00	115.00	41.60
37			41.60	4.16	
38			41.60	12.50	
39	Hetland, SD 115kv	Transmission	115.00	41.60	
40	Hoot Lake Plant, Fergus Falls, MN	Transmission	14.40	41.60	

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	Hoot Lake 115 kv, Fergus Falls, MN	Transmission	14.40	115.00	
2			14.40	115.00	
3			115.00	43.80	
4			115.00	12.50	
5	Jamestown, ND 345 kv	Transmission	345.00	115.00	43.00
6			41.60	2.40	
7			41.60	2.40	
8	Jamestown, ND Peaking Plant	Transmission	115.00	41.60	
9			41.60	12.50	
10			41.60	7.20	
11	Lake Preston, SD Peaking Plant	Transmission	41.60	12.50	
12			41.60	4.16	
13			12.50	4.16	
14	Maple River	Transmission	345.00	230.00	13.80
15	Mapleton, ND 115 kv	Transmission	115.00	41.60	
16	Marietta, MN 115 kv	Transmission	115.00	41.60	
17			41.60	2.40	
18	Northwood, ND 115kv	Transmission	115.00	41.60	
19	Oakes, ND 230 kv	Transmission	230.00	41.60	
20			41.60	4.16	
21	Ortonville, MN 115 kv	Transmission	115.00	41.60	
22	Pelican Rapids, MN	Transmission	115.00	41.60	
23			41.60	2.40	
24	Plummer, MN 115 kv	Transmission	115.00	41.60	
25	Rugby, ND 230 kv	Transmission	230.00	115.00	13.80
26	Solway, MN 115 kv	Transmission	115.00	13.80	
27	Toronto, SD	Transmission	115.00	41.60	
28			41.60	2.40	
29	Wahpeton, ND North	Transmission	115.00	41.60	
30	Wilton, MN	Transmission	230.00	115.00	13.80
31			41.60	2.40	
32	Winger, MN	Transmission	230.00	115.00	
33			41.60	7.20	
34			41.60	2.40	
35					
36	Transmission Subtotal:		7566.40	3115.76	210.40
37	Transmission Subs Under 10,000 kva				
38	Transmission Total		7566.40	3115.76	210.40
39					
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	Bemidji, MN Airport	Distribution	41.60	12.50	
2	Bemidji, MN 25th Street	Distribution	69.00	12.50	
3	Bemidji, MN Nymore	Distribution	69.00	12.50	
4	Bemidji, MN Potlatch	Distribution	69.00	12.50	
5	Casselton, ND	Distribution	41.60	12.50	
6	Cooperstown, ND	Distribution	41.60	12.50	
7	Crookston, MN Uptown	Distribution	41.60	12.50	
8	Crookston, MN Parkview	Distribution	41.60	12.50	
9	Crookston, MN Simplot Jiffy Fry	Distribution	41.60	12.50	
10	Dawson, MN Dawson Mills	Distribution	41.60	12.50	
11	Devils Lake, ND Downtown	Distribution	41.60	4.16	
12	Enderlin, ND	Distribution	115.00	12.50	
13	Fairmount, ND	Distribution	69.00	12.50	
14	Gwinner, ND	Distribution	115.00	12.50	
15	Harvey, ND Northwest	Distribution	115.00	12.50	
16	Itasca, MN Minnesota Pipeline	Distribution	115.00	4.16	
17	Jamestown, ND Southwest	Distribution	41.60	12.50	
18	Jamestown, ND Downtown	Distribution	41.60	12.50	
19	Jamestown, ND Potato	Distribution	41.60	12.50	
20	Jamestown, ND North	Distribution	41.60	12.50	
21	Lake Norden, SD Dairy	Distribution	41.60	12.50	
22	Lisbon, ND Town	Distribution	115.00	12.50	
23	Mahnomen, MN	Distribution	115.00	12.50	
24	Milbank, SD South	Distribution	41.60	12.50	
25	Milbank, SD Northwest	Distribution	41.60	12.50	
26	Morris, MN South	Distribution	41.60	12.50	
27	Morris, MN East	Distribution	41.60	12.50	
28	Perham, MN	Distribution	41.60	12.50	
29	Pelican Rapids, MN Turkey Plant	Distribution	41.60	12.50	
30	Rosholt, SD	Distribution	41.60	12.50	
31	Rugby, ND South	Distribution	41.60	12.50	
32	Spiritwood, ND Ladish	Distribution	41.60	12.50	
33	Spiritwood, ND Ladish	Distribution	115.00	41.60	
34	Wahpeton, ND Northwest	Distribution	41.60	12.50	
35	Wheaton, MN South	Distribution	115.00	12.50	
36	Distribution Subtotal:		2152.80	449.92	
37	Distribution Under 10,000 kva				
38	Distribution Total		2152.80	449.92	
39	Transmission From Above				
40	Transmission & Distribution				

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.
18	1					1
	3					2
2	3					3
45	1					4
460	1					5
233	1					6
39	1					7
16	1					8
26	1					9
5	1					10
112	1					11
2	3					12
	1					13
27	1					14
5	1					15
19	1					16
11	1					17
11	1					18
	3					19
39	1					20
56	1					21
	1					22
336	1					23
34	1					24
	3					25
57	1					26
10	1					27
10	1					28
3	1					29
37	1					30
10	1					31
1	3					32
60	1					33
2	3					34
	1					35
140	1					36
2	1					37
	1					38
45	1					39
10	1					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.
84	1					1
60	1					2
27	1					3
37	1					4
224	2					5
1	3					6
3	1					7
56	1					8
56	2					9
5	1					10
28	1					11
3	1					12
1	3					13
672	2					14
20	1					15
10	1					16
	1					17
13	1					18
34	1					19
	3					20
22	1					21
12	1					22
	2					23
34	1					24
125	1					25
80	1					26
45	1					27
	1					28
24	2					29
140	1					30
1	3					31
140	1					32
1	3					33
	1					34
						35
3841	103					36
35	31					37
3876	134					38
						39
						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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
14	1					1
15	1					2
14	1					3
11	1					4
10	1					5
10	1					6
15	1					7
10	1					8
10	1					9
10	1					10
10	1					11
19	2					12
10	3					13
20	2					14
14	1					15
11	1					16
14	1					17
14	1					18
14	1					19
14	1					20
12	1					21
14	1					22
14	1					23
10	1					24
25	1					25
12	3					26
12	1					27
28	2					28
10	1					29
10	1					30
10	1					31
50	2					32
25	1					33
20	2					34
12	1					35
523	44					36
881	950					37
1404	994					38
3876						39
5280						40

Schedule Page: 426 Line No.: 5 Column: a

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

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

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