

THIS FILING IS

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

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



FERC FINANCIAL REPORT

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

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

3 PU-10-153 Filed 11/17/2010 Pages: 327
 FERC Financial Report
 Public Service Commission

Exact Legal Name of Respondent (Company)

Northern States Power Company (Minnesota)

Year/Period of Report

End of 2009/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

- (1) one million megawatt hours of total annual sales,
- (2) 100 megawatt hours of annual sales for resale,
- (3) 500 megawatt hours of annual power exchanges delivered, or
- (4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: <http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp>. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

- a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and
- b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

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

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

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

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

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

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

- (g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from <http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf> and <http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas>.

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

- a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and
- b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Northern States Power Company (Minnesota)		02 Year/Period of Report End of 2009/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) 414 Nicollet Mall, Minneapolis, Minn. 55401			
05 Name of Contact Person Teresa S. Madden		06 Title of Contact Person Vice President and Controller	
07 Address of Contact Person (Street, City, State, Zip Code) 414 Nicollet Mall, Minneapolis, Minn. 55401			
08 Telephone of Contact Person, Including Area Code (612) 215-4560	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> 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 Teresa S. Madden	03 Signature Teresa S. Madden	04 Date Signed (Mo, Da, Yr) 04/16/2010
02 Title Vice President and Controller		

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

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	none
25	Unrecovered Plant and Regulatory Study Costs	230	none
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	none
32	Capital Stock Expense	254	none
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Sales of Electricity by Rate Schedules	304	
44	Sales for Resale	310-311	
45	Electric Operation and Maintenance Expenses	320-323	
46	Purchased Power	326-327	
47	Transmission of Electricity for Others	328-330	
48	Transmission of Electricity by ISO/RTOs	331	none
49	Transmission of Electricity by Others	332	
50	Miscellaneous General Expenses-Electric	335	
51	Depreciation and Amortization of Electric Plant	336-337	
52	Regulatory Commission Expenses	350-351	
53	Research, Development and Demonstration Activities	352-353	
54	Distribution of Salaries and Wages	354-355	
55	Common Utility Plant and Expenses	356	
56	Amounts included in ISO/RTO Settlement Statements	397	
57	Purchase and Sale of Ancillary Services	398	
58	Monthly Transmission System Peak Load	400	
59	Monthly ISO/RTO Transmission System Peak Load	400a	none
60	Electric Energy Account	401	
61	Monthly Peaks and Output	401	
62	Steam Electric Generating Plant Statistics	402-403	
63	Hydroelectric Generating Plant Statistics	406-407	
64	Pumped Storage Generating Plant Statistics	408-409	none
65	Generating Plant Statistics Pages	410-411	
66	Transmission Line Statistics Pages	422-423	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Lines Added During the Year	424-425	
68	Substations	426-427	
69	Transactions with Associated (Affiliated) Companies	429	
70	Footnote Data	450	
	Stockholders' Reports Check appropriate box: <input type="checkbox"/> Two copies will be submitted <input type="checkbox"/> No annual report to stockholders is prepared		

Name of Respondent Northern States Power Company (Minnesota)	This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of <u>2009/Q4</u>
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GENERAL INFORMATION

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

Teresa S. Madden
Vice President and Controller
 414 Nicollet Mall, Suite 400
 Minneapolis, Minn. 55401

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.

Northern States Power Co. (a Minnesota corporation) was incorporated in the state of Minnesota on March 8, 2000.

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.

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

During the year 2009, the respondent furnished electric utility and natural gas utility service in the states of Minnesota and North Dakota and electric utility and intrastate natural gas transportation service in the state of South Dakota.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

- (1) Yes...Enter the date when such independent accountant was initially engaged:
- (2) No

Name of Respondent Northern States Power Company (Minnesota)	This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of <u>2009/Q4</u>
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CONTROL OVER RESPONDENT

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

Northern States Power Co. (a Minnesota corporation) is a first tier subsidiary of Xcel Energy Inc.

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	NSP Nuclear Corp.	Holds NSP's interest in	100.0	
2		Nuclear Mgmt Co. LLC		
3	Nuclear Mgmt Co. LLC	Manages nuclear power plants	100.0	
4	Private Fuel Storage LLC	Nuclear waste storage	32.8	
5	United Power and Land Co.	Real estate holdings	100.0	
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OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is \$50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.

2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chairman of the Board	Richard C. Kelly	451,435
2	President and Chief Executive Officer	Judy M. Pofert	220,170
3	Vice President and Chief Financial Officer	David M. Sparby	265,935
4	Vice President and General Counsel	Michael C. Connelly	165,249
5	Vice President and Chief Nuclear Officer	Dennis L. Koehl	415,000
6	Vice President and Controller	Teresa S. Madden	114,975
7	Vice President and Secretary	Cathy J. Hart	111,979
8	Vice President and Treasurer	George E. Tyson II	111,396
9	Vice President	Benjamin G. S. Fowke III	246,423
10	Vice President	David M. Wilks	172,142
11	Vice President	Marvin E. McDaniel, Jr.	140,650
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14	Salaries represent NSP-Minnesota's allocation of		
15	officers' salaries greater than \$50,000 for the period		
16	of time that was served as an officer for		
17	NSP-Minnesota.		
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Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 104 Line No.: 2 Column: b

Judy M. Poferl was elected as President and Chief Executive Officer of NSP-Minnesota on Aug. 26, 2009.

Schedule Page: 104 Line No.: 3 Column: b

David M. Sparby resigned as President and Chief Executive Officer of NSP-Minnesota on Aug. 26, 2009. He was elected as Vice President and Chief Financial Officer of NSP-Minnesota on Aug. 26, 2009.

Schedule Page: 104 Line No.: 9 Column: b

Benjamin G.S. Fowke III resigned as Chief Financial Officer of NSP-Minnesota on Aug. 26, 2009.

Schedule Page: 104 Line No.: 10 Column: b

David M. Wilks resigned as Vice President of NSP-Minnesota on March 31, 2010. Kent T. Larson was elected as Vice President of NSP-Minnesota on March 31, 2010.

Schedule Page: 104 Line No.: 11 Column: b

Marvin E. McDaniel, Jr. was elected as Vice President of NSP-Minnesota on Aug. 26, 2009.

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	Richard C. Kelly, Chairman of the Board	414 Nicollet Mall Suite 500, Minneapolis, Minn. 55401
2	Benjamin G. S. Fowke III, Vice President	414 Nicollet Mall Suite 500, Minneapolis, Minn. 55401
3	Judy M. Pofert, President and Chief Executive Officer	414 Nicollet Mall Suite 500, Minneapolis, Minn. 55401
4	David M. Sparby, Vice President and Chief Financial Officer	414 Nicollet Mall Suite 500, Minneapolis, Minn. 55401
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	/ /	2009/Q4
FOOTNOTE DATA			

Schedule Page: 105 Line No.: 3 Column: a

Judy M. Poferl was elected as a Director of NSP-Minnesota effective Aug. 26, 2009.

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

Does the respondent have formula rates? Yes No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff, Third Revised Volume No. 1	ER07-1415-000 - Order Granting Incentives,
2	(Midwest Independent Transmission System	and Accepting Proposed Rate Formula
3	Operator, Inc. Open Access Transmission and	Modifications, Subject to Conditions, Issued
4	Energy Markets Tariff, Attachment O-NSP)	December 21, 2007, Accession No.
5		20071221-3012.
6		
7	FERC Electric Tariff, Fourth Revised Volume No. 1	ER10-541-000 - Approval of Tariff Revisions to
8	(Midwest Independent Transmission System	Attachment O-NSP, Issued February 26, 2010,
9	Operator, Inc. Open Access Transmission and	Accession No. 20100226-3041.
10	Energy Markets Tariff, Attachment O-NSP)	
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

Yes
 No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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INFORMATION ON FORMULA RATES
 Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1	111	Comparative Bal Sheet (Assets & Other Dfrd Debits)		(c) 57
2	205, 207	Electric Plant in Service (Acct 101-103, 106)		(g) 5, 46, 58, 75, 99
3	214	Electric Plant Held for Future Use (Acct 105)		(d) 47
4	216	Construction Work in Progress--Electric (Acct 107)		(b) 43
5	219	Accum Prov for Depr of Elect Util Plant Acct 108		(c) 20-26, 28
6	227	Materials and Supplies		(c) 8, 16
7	234	Accumulated Deferred Income Taxes (Acct 190)		(c) 8
8	267	Accumulated Deferred Income Tax Credits (Acct 255)		(h) 8
9	269	Other Deferred Credits (Account 253)		(f) 47
10	273	Accumulated Deferred Income Taxes (Acct 281)		(k) 8
11	275	Accumulated Deferred Income Taxes (Acct 282)		(k) 2
12	277	Accumulated Deferred Income Taxes (Acct 283)		(k) 9
13	300	Electric Operating Revenues (Account 400)		(b) 19
14	311	Sales for Resale (Account 447)		(k) Total
15	321	Electric Operation and Maintenance Expenses		(b) 112
16	330	Transmission of Electricity for Others (Acct 456)		(n) Total
17	356.1	Common Utility Plant and Expenses		n/a n/a
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 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.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	/ /	2009/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

ITEM NUMBER 1 - The following franchises were acquired from the representative local government body without payment of consideration:

City	State	Utility	Expiration
Cosmos	MN	Gas	Aug. 12, 2029
Center City	MN	Electric	Nov. 1, 2029
Center City	MN	Gas	Nov. 1, 2029
Inver Grove Heights	MN	Electric	Nov. 22, 2029
Inver Grove Heights	MN	Gas	Nov. 22, 2029
Watertown	MN	Gas	Nov. 23, 2029
Arden Hills	MN	Electric	Nov. 30, 2029
Arden Hills	MN	Gas	Nov. 30, 2029
North Oaks	MN	Electric	Dec. 6, 2029
North Oaks	MN	Gas	Dec. 6, 2029
Reynolds	ND	Electric	Dec. 6, 2029
Thompson	ND	Electric	Dec. 6, 2029

ITEM NUMBER 2 - None

ITEM NUMBER 3 - None

ITEM NUMBER 4 - None

ITEM NUMBER 5 - None

ITEM NUMBER 6 - Short-term debt obligations decreased \$65,000,000 during 2009. Also, see Note 4 to Notes to Financial Statements on page 122 for additional information on short-term debt. On Nov. 17, 2009, Northern States Power Co. (a Minnesota corporation) (NSP-Minnesota) issued \$300 million of 5.35 percent First Mortgage Bonds, Series due Nov. 1, 2039. These securities issuances are within levels authorized by the MPUC in its Docket No. E, G-002/S-08-1180.

ITEM NUMBER 7 - None

ITEM NUMBER 8 - 2009 Annual Salary Increase:

- 1) Union Employees - Base wage increase of 3.50 percent.
- 2) Non-Union Employees - Merit base increase of 2.00 percent effective July 1, 2009.

ITEM NUMBER 9 - See Note 5 to Notes to Financial Statements on page 122.

ITEM NUMBER 10 - None

ITEM NUMBER 11 - Not applicable

ITEM NUMBER 12 - None

ITEM NUMBER 13 - The following changes in officers occurred during 2009.

Raymond E. Gogel resigned as Vice President on April 10, 2009.

Judy M. Poferl was elected as Director, President and Chief Executive Officer of NSP-Minnesota, effective Aug. 26, 2009.

David M. Sparby resigned as President and Chief Executive Officer of NSP-Minnesota and was elected Vice President and Chief Financial Officer of NSP-Minnesota, effective Aug. 26, 2009.

Benjamin G. S. Fowke III resigned as Chief Financial Officer of NSP-Minnesota, effective Aug. 26, 2009. He retained his title of Vice President of NSP-Minnesota.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr)	
Northern States Power Company (Minnesota)		/ /	2009/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Marvin E. McDaniel was elected as a Vice President of NSP-Minnesota, effective Aug. 26, 2009.

David M. Wilks resigned as Vice President of NSP-Minnesota, effective as of March 31, 2010.

Kent T. Larson was elected as Vice President of NSP-Minnesota, effective as of March 31, 2010.

ITEM NUMBER 14 - None

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	11,187,831,182	10,906,942,774
3	Construction Work in Progress (107)	200-201	588,011,455	633,750,862
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		11,775,842,637	11,540,693,636
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	5,397,551,717	5,256,400,834
6	Net Utility Plant (Enter Total of line 4 less 5)		6,378,290,920	6,284,292,802
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202-203	108,914,726	131,327,109
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		70,089	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		399,370,870	307,037,358
10	Spent Nuclear Fuel (120.4)		1,229,113,325	1,172,828,794
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	1,435,677,031	1,355,572,641
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		301,791,979	255,620,620
14	Net Utility Plant (Enter Total of lines 6 and 13)		6,680,082,899	6,539,913,422
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		7,556,420	8,455,374
19	(Less) Accum. Prov. for Depr. and Amort. (122)		5,167,056	5,413,057
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	2,713,920	1,750,394
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)		15,947,586	9,532,624
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		1,248,739,175	1,075,294,351
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		117,131,330	129,604,515
31	Long-Term Portion of Derivative Assets – Hedges (176)		84,827	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,387,006,202	1,219,224,201
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		0	0
36	Special Deposits (132-134)		6,683,806	1,648,462
37	Working Fund (135)		175,471	236,500
38	Temporary Cash Investments (136)		39,393,488	11,616,750
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		292,650,295	336,842,121
41	Other Accounts Receivable (143)		28,864,443	59,827,947
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		22,674,706	25,698,811
43	Notes Receivable from Associated Companies (145)		22,500,000	380,000
44	Accounts Receivable from Assoc. Companies (146)		31,307,781	12,418,057
45	Fuel Stock (151)	227	103,697,089	145,713,731
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	104,989,347	97,471,938
49	Merchandise (155)	227	454,361	459,272
50	Other Materials and Supplies (156)	227	64,565	13,389
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	1
55	Gas Stored Underground - Current (164.1)		35,910,763	91,122,695
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		10,803,521	11,121,641
57	Prepayments (165)		36,046,461	60,131,668
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		517,422	0
60	Rents Receivable (172)		617,337	966,496
61	Accrued Utility Revenues (173)		229,337,776	248,451,387
62	Miscellaneous Current and Accrued Assets (174)		2,544,292	2,065,857
63	Derivative Instrument Assets (175)		176,613,716	161,374,914
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		117,131,330	129,604,515
65	Derivative Instrument Assets - Hedges (176)		84,827	38,481,617
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		84,827	0
67	Total Current and Accrued Assets (Lines 34 through 66)		983,365,898	1,125,041,117
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		23,661,678	21,303,455
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	2,073,802,375	2,058,913,137
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	-1
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	1,663,681	1,558,746
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)		23,504,891	26,081,631
82	Accumulated Deferred Income Taxes (190)	234	387,736,220	371,855,418
83	Unrecovered Purchased Gas Costs (191)		18,132,638	30,061,810
84	Total Deferred Debits (lines 69 through 83)		2,528,501,483	2,509,774,196
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		11,578,956,482	11,393,952,936

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
FOOTNOTE DATA			

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

Prepayments (Account 165). The Form 1 reports prepayments at the total Company level, at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of the year prepayments balance in the formula. In addition, since prepayments are reported in the Form 1 at the total Company level, they are allocated to the electric utility based on the ratio of electric net plant to the sum of electric and gas net plant as reported in the Form 1, page 200. The formula allocates the electric prepayments to the transmission function using a gross plant allocator.

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	10,000	10,000
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		2,028,592,307	1,915,856,608
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	1,213,172,788	1,153,074,830
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-2,278,694	-3,242,219
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)	1,712,266	204,740
16	Total Proprietary Capital (lines 2 through 15)		3,241,208,667	3,065,903,959
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	3,021,900,000	2,721,900,000
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	66,511	250,107,167
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		8,788,123	9,257,796
24	Total Long-Term Debt (lines 18 through 23)		3,013,178,388	2,962,749,371
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)		3,793,000	0
29	Accumulated Provision for Pensions and Benefits (228.3)		281,427,000	238,959,090
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		63,490,529	5,500,487
32	Long-Term Portion of Derivative Instrument Liabilities		209,527,868	219,421,415
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		797,476,012	1,055,689,152
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,355,714,409	1,519,570,144
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	65,000,000
38	Accounts Payable (232)		369,648,567	360,020,217
39	Notes Payable to Associated Companies (233)		2,500,000	63,500,000
40	Accounts Payable to Associated Companies (234)		83,759,095	52,378,892
41	Customer Deposits (235)		2,280,611	1,831,439
42	Taxes Accrued (236)	262-263	132,129,980	128,562,585
43	Interest Accrued (237)		62,780,010	67,989,956
44	Dividends Declared (238)		58,415,165	58,414,593
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		15,568,261	13,299,408
48	Miscellaneous Current and Accrued Liabilities (242)		4,710,693	52,384,250
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		231,923,653	238,807,851
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		209,527,868	219,421,415
52	Derivative Instrument Liabilities - Hedges (245)		2,265,419	20,429,401
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		756,453,586	903,197,177
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		2,111,532	2,142,774
57	Accumulated Deferred Investment Tax Credits (255)	266-267	37,134,212	40,253,724
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	202,847,064	192,778,030
60	Other Regulatory Liabilities (254)	278	1,384,905,742	1,365,366,880
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	17,461,092	7,079,027
63	Accum. Deferred Income Taxes-Other Property (282)		1,453,630,977	1,242,755,908
64	Accum. Deferred Income Taxes-Other (283)		114,310,813	92,155,942
65	Total Deferred Credits (lines 56 through 64)		3,212,401,432	2,942,532,285
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		11,578,956,482	11,393,952,936

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	4,113,225,655	4,571,710,776		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,736,183,304	3,212,382,957		
5	Maintenance Expenses (402)	320-323	225,354,441	201,282,033		
6	Depreciation Expense (403)	336-337	321,404,264	368,892,839		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	-40,842,047	-162,492		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	23,935,494	30,943,465		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337		14,770		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		44,396,299	10,416,577		
13	(Less) Regulatory Credits (407.4)		26,585,722	74,705,241		
14	Taxes Other Than Income Taxes (408.1)	262-263	147,597,577	138,368,526		
15	Income Taxes - Federal (409.1)	262-263	-12,108,947	16,671,051		
16	- Other (409.1)	262-263	10,848,670	12,222,188		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	280,802,797	204,419,827		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	107,277,470	68,505,301		
19	Investment Tax Credit Adj. - Net (411.4)	266	-3,119,512	-3,503,402		
20	(Less) Gains from Disp. of Utility Plant (411.6)			3,695		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		548,918	577,125		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		63,979,728	74,080,262		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		3,664,019,958	4,122,237,239		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		449,205,697	449,473,537		

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
3,467,568,383	3,673,215,479	645,358,220	898,196,245	299,052	299,052	2
						3
2,200,410,589	2,429,789,152	535,772,715	782,593,805			4
217,593,184	193,566,072	7,761,257	7,715,961			5
289,876,863	338,824,582	31,527,401	30,068,257			6
-40,821,319	-139,913	-20,728	-22,579			7
19,983,896	26,362,359	3,875,041	4,503,649	76,557	77,457	8
	14,770					9
						10
						11
44,396,141	10,224,393	158	192,184			12
26,576,668	74,405,772	9,054	299,469			13
131,823,602	123,657,601	15,773,975	14,710,925			14
-9,172,463	13,376,682	-2,936,484	3,294,369			15
10,894,123	10,866,162	-45,453	1,356,026			16
248,928,722	182,884,582	31,874,075	21,535,245			17
90,590,506	54,953,465	16,686,964	13,551,836			18
-2,790,747	-3,194,797	-328,765	-308,605			19
	3,695					20
						21
548,918	577,125					22
						23
63,958,959	73,760,001	20,769	320,261			24
3,057,365,458	3,270,051,589	606,577,943	852,108,193	76,557	77,457	25
410,202,925	403,163,890	38,780,277	46,088,052	222,495	221,595	26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
			Current Year (c)	Previous Year (d)		
27	Net Utility Operating Income (Carried forward from page 114)		449,205,697	449,473,537		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		19,084,963	18,061,234		
34	(Less) Expenses of Nonutility Operations (417.1)		14,292,074	13,168,463		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	963,526	-1,860,676		
37	Interest and Dividend Income (419)		2,386,536	8,977,833		
38	Allowance for Other Funds Used During Construction (419.1)		28,848,079	26,510,189		
39	Miscellaneous Nonoperating Income (421)		2,633,813	2,315,519		
40	Gain on Disposition of Property (421.1)		156,554	5,558		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		39,781,397	40,841,194		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			2,982		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		5,424,476	5,349,820		
46	Life Insurance (426.2)		-3,661,482	-1,657,238		
47	Penalties (426.3)		3,826,145	-20,899		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,731,537	2,899,301		
49	Other Deductions (426.5)		4,463,494	1,704,617		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		12,784,170	8,278,583		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	214,114	228,138		
53	Income Taxes-Federal (409.2)	262-263	-4,996,752	5,944,686		
54	Income Taxes-Other (409.2)	262-263	7,658,926	14,178,698		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	12,588,498	15,912,601		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	10,057,007	20,425,983		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		5,407,779	15,838,140		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		21,589,448	16,724,471		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		186,474,598	186,164,606		
63	Amort. of Debt Disc. and Expense (428)		2,771,024	2,802,087		
64	Amortization of Loss on Reaquired Debt (428.1)		2,576,740	2,583,800		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		572,767	1,502,698		
68	Other Interest Expense (431)		2,389,306	5,143,655		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		17,759,630	17,139,853		
70	Net Interest Charges (Total of lines 62 thru 69)		177,024,805	181,056,993		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		293,770,340	285,141,015		
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)		293,770,340	285,141,015		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2009/Q4
FOOTNOTE DATA			

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

Revenue from Plant Leased to Others

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

Revenue from Plant Leased to Others

Schedule Page: 114 Line No.: 8 Column: k

Expenses of Plant Leased to Others

Schedule Page: 114 Line No.: 8 Column: l

Expenses of Plant Leased to Others

Schedule Page: 114 Line No.: 22 Column: c

Gains on sale of SO2 Emissions Allowances:
Reconcile gains reported on p 114-7, 229, and 278

	p 114-7 Income Account Acct No. 411.8	p 278 Regulatory Liabilities Acct No. 254	p 229 Gain on Sale
Dec. 31, 2007		<u>(2,885,465)</u>	
Amortize past years' gains to income	(577,125)	577,125	
System gains during 2008		(536,683)	(536,683)
less portion due NSP-Wisconsin based on energy used		77,291	
less portion due SMMPA		40,524	40,524
less gains from allowances relating to a plant owned by NSP-Wisconsin			8,944
subtotal 2008 gains	<u>(577,125)</u>	<u>158,257</u>	<u>(487,215)</u>
Dec. 31, 2008		<u>(2,727,208)</u>	
Amortize past years' gains to income	(548,918)	548,918	
System gains during 2009		(77,953)	(77,953)
less portion due NSP-Wisconsin based on energy used		11,615	
less portion due SMMPA		5,887	5,887
less gains from allowances relating to a plant owned by NSP-Wisconsin			1,299
subtotal 2009 gains	<u>(548,918)</u>	<u>488,467</u>	<u>(70,767)</u>
Dec. 31, 2009		<u>(2,238,741)</u>	

Page 114 and Page 278 gains are shared between Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) based on the portion of energy that each uses from the NSP System. Page 229 reports only the gains relating to plants owned by NSP-Minnesota.

Schedule Page: 114 Line No.: 46 Column: c

Income on Company Owned Life Insurance.

Schedule Page: 114 Line No.: 46 Column: d

Income on Company Owned Life Insurance.

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		1,152,997,207	1,100,508,412
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6	Rounding		1	1
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		1	1
10				
11	Adoption of new accounting guidance for endorsement			
12	split-dollar life insurance	146		(633,171)
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			(633,171)
16	Balance Transferred from Income (Account 433 less Account 418.1)		292,806,814	287,001,691
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-232,708,857	(232,032,578)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-232,708,857	(232,032,578)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			(1,847,148)
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,213,095,165	1,152,997,207
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		77,623	77,623
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		77,623	77,623
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,213,172,788	1,153,074,830
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-3,242,219	(3,228,691)
50	Equity in Earnings for Year (Credit) (Account 418.1)		963,526	(1,860,676)
51	(Less) Dividends Received (Debit)			(1,847,148)
52	Rounding		-1	
53	Balance-End of Year (Total lines 49 thru 52)		-2,278,694	(3,242,219)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 118 Line No.: 12 Column: b

Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split-Dollar Life Insurance Arrangements - In June 2006, the FASB issued new guidance on the recognition of a liability and related compensation costs for endorsement split-dollar life insurance policies that provide a benefit to an employee that extends to postretirement periods. Therefore, this guidance would not apply to a split-dollar life insurance arrangement that provides a specified benefit to an employee that is limited to the employee's active service period with an employer. The new guidance was effective for fiscal years beginning after Dec. 15, 2007, with earlier application permitted. Upon adoption of the guidance on Jan 1, 2008, NSP-Minnesota recorded a liability of \$0.6 million, net of tax, as a reduction of retained earnings. Thereafter, changes in the liability will be reflected in operating results.

Schedule Page: 118 Line No.: 37 Column: d

The credit is a reclassification of a portion of 2007's reported dividend, in 2008, which was a return of investment and not a dividend of retained earnings.

Schedule Page: 118 Line No.: 51 Column: d

The credit represents the reclassification, in 2008, of a portion of 2007's reported dividend which was a return of investment and not a dividend of retained earnings.

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)	293,770,340	285,141,015
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	389,364,371	367,985,321
5	Amortization of Nuclear Fuel	80,104,390	64,203,047
6	Amortization of Premium, Discount and Debt Expense	5,347,764	5,385,887
7	Amortization of Deferred Debits/Credits		10,315,158
8	Deferred Income Taxes (Net)	175,998,617	131,401,143
9	Investment Tax Credit Adjustment (Net)	-3,119,512	-3,503,402
10	Net (Increase) Decrease in Receivables	53,241,501	18,539,819
11	Net (Increase) Decrease in Inventory	89,983,021	-75,272,337
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	34,728,435	-19,597,783
14	Net (Increase) Decrease in Other Regulatory Assets	-84,819,776	1,193,754
15	Net Increase (Decrease) in Other Regulatory Liabilities	1,860,162	-37,896,337
16	(Less) Allowance for Other Funds Used During Construction	28,848,079	26,510,189
17	(Less) Undistributed Earnings from Subsidiary Companies	963,526	-1,860,676
18	Increase/Decrease in Accrued Utility Revenues	19,113,611	-22,049,928
19	Net Realized and Unrealized Hedging and Derivative Transactions	-4,960,023	
20	Miscellaneous Changes in Working Capital	-14,981,374	72,367,369
21	Changes in Other Assets and Liabilities	51,167,773	38,500,541
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,056,987,695	812,063,754
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-696,415,203	-857,063,512
27	Gross Additions to Nuclear Fuel	-126,275,749	-139,964,161
28	Gross Additions to Common Utility Plant	-21,763,327	-18,799,240
29	Gross Additions to Nonutility Plant	-101,879	
30	(Less) Allowance for Other Funds Used During Construction	-28,848,079	-26,510,189
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-815,708,079	-989,316,724
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	-59,870,000	-442,762,186
40	Contributions and Advances from Assoc. and Subsidiary Companies	47,250,000	489,514,944
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	Investments in Utility Money Pool Arrangement	-132,500,000	-943,400,000
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.

(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.

(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.

(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Repayments from Utility Money Pool Arrangement	125,500,000	943,400,000
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: Miscellaneous Other Investing Activities	-11,450,305	8,941,099
54	Other: Purchase of Investments in External Decommissioning Fund	-1,644,278,201	-957,752,102
55	Other: Proceeds from Sale of Investments in External Decommissioning	1,664,957,414	914,513,535
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-826,099,171	-976,861,434
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	295,340,427	493,751,019
62	Preferred Stock		
63	Common Stock		
64	Other: Capital Contributions from Parent	112,735,699	203,863,071
65			
66	Net Increase in Short-Term Debt (c)		
67	Other: Borrowings Under Utility Money Pool Arrangement	601,700,000	433,300,000
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,009,776,126	1,130,914,090
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-250,040,656	-9,777
74	Preferred Stock		
75	Common Stock		
76	Other: Repayments Under Utility Money Pool Arrangement	-665,200,000	-464,900,000
77			
78	Net Decrease in Short-Term Debt (c)	-65,000,000	-276,500,000
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-232,708,285	-229,711,704
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-203,172,815	159,792,609
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	27,715,709	-5,005,071
87			
88	Cash and Cash Equivalents at Beginning of Period	11,853,250	16,858,321
89			
90	Cash and Cash Equivalents at End of period	39,568,959	11,853,250

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FOOTNOTE DATA			

Schedule Page: 120 Line No.: 10 Column: b
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<u>Change in Accounts Receivable</u>	<u>2009</u>
Provision for bad debts	\$ 19,407,676
Change in accounts receivable	<u>33,833,825</u>
	\$ 53,241,501

Schedule Page: 120 Line No.: 10 Column: c
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<u>Change in Accounts Receivable</u>	<u>2008</u>
Provision for bad debts	\$ 25,505,978
Change in accounts receivable	<u>(6,966,159)</u>
	\$ 18,539,819

NOTES TO FINANCIAL STATEMENTS

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

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

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NOTES TO FINANCIAL STATEMENTS (Continued)			

1. Significant Accounting Policies

Business and System of Accounts — NSP-Minnesota is principally engaged in the generation, purchase, transmission, distribution and sale of electricity and in the purchase, transportation, distribution and sale of natural gas. NSP-Minnesota is subject to regulation by the FERC and state utility commissions. All of NSP-Minnesota's accounting records conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions, which are the same in all material respects.

Basis of Accounting - The accompanying financial statements were prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles (GAAP). As required by the FERC, NSP-Minnesota accounts for its investment in majority-owned subsidiaries using the equity method rather than consolidating the assets, liabilities, revenues, and expenses of these subsidiaries as required by GAAP. Deferred taxes are shown as long-term assets and liabilities at their gross amounts in the FERC presentation, in contrast to the GAAP presentation as net current or long-term assets and liabilities. Accounting for the investments in majority-owned subsidiaries on the equity method and classifying certain deferred income taxes as long-term assets or long-term liabilities, rather than in accordance with GAAP, have no effect on net income and no material effect on retained earnings.

Estimated removal costs for future removal obligations are classified as accumulated depreciation on the utility plant in the FERC presentation and regulatory liabilities in the GAAP presentation. Also, all Allowance for Funds Used During Construction (AFDC) is included in construction work in process, or plant in service when appropriate, with an offsetting other deferred liability for costs associated with enhanced recovery mechanism projects.

As a result of adopting the recognition and measurement provisions of *ASC 740 Income Taxes* for GAAP reporting, the amount of benefit recognized on the balance sheet may differ from the amount taken or expected to be taken in a tax return, resulting in unrecognized tax benefits. A liability is created for an unrecognized tax benefit or the amount of a net operating loss carryforward or amount refundable is reduced. The liability is recorded in accounts separate from the accounts established for accumulated deferred income taxes, as required by *ASC 740*. Conversely, FERC reporting requires uncertainties from tax positions involving temporary differences to be recorded in accounts established for accumulated deferred income taxes.

If GAAP were followed, these financial statement line items would have values greater/(lesser) than those shown by FERC presentation of:

(\$ in thousands)	
Net utility plant	\$ 278,573
Current assets	73,640
Current liabilities	240,701
Other long-term assets	(1,712,360)
Long-term debt and other long-term liabilities	(1,600,849)

NSP-Minnesota reports its net margin (revenues less expenses) from trading activities as revenue for GAAP reporting but it reports revenues and expenses separately for FERC reporting. Income tax expense is shown as a component of operating expense in the FERC presentation, in contrast to its GAAP presentation as a below-the-line deduction from operating income. This classification difference has no impact on net income.

(\$ in thousands)	
Operating revenues	\$ (46,537)
Operating expenses	(212,850)
Other income and deductions	8,831
Cash provided by operating activities	4,089
Cash used in investing activities	2,155
Cash used in financing activities	—

Revenue Recognition — Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meter, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date

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of the last meter reading are estimated and the corresponding unbilled revenue is estimated. NSP-Minnesota presents its revenue net of any excise or other fiduciary-type taxes or fees.

NSP-Minnesota has various rate-adjustment mechanisms in place that currently provide for the recovery of natural gas and electric fuel costs, as well as purchased energy costs. These cost-adjustment tariffs may increase or decrease the level of costs recovered through base rates and are revised periodically for any difference between the total amount collected under the clauses and the recoverable costs incurred. Where applicable, under governing state regulatory commission rate orders, fuel costs over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. A summary of significant rate adjustment mechanisms follows:

- NSP-Minnesota's rates include a cost-of-fuel-and-purchased-energy and a cost-of-gas recovery mechanism allowing recovery of the respective costs, which are trued-up on a two-month and annual basis, respectively. The electric cost-of-fuel-and-purchased-energy mechanism in North Dakota also provides a sharing among shareholders and customers of certain margins on short-term wholesale and commodity trading. NSP Minnesota's rates include a rider for cost recovery of DSM program costs as well as recovery of a financial incentive for meeting energy savings goals.
- NSP-Minnesota operates under various service quality standards, which could require customer refunds if certain criteria are not met. NSP-Minnesota's rates in Minnesota include monthly adjustments for the recovery of conservation and energy-management program costs, which are reviewed annually. NSP-Minnesota is allowed to recover certain costs associated with new transmission facilities to deliver renewable energy resources and certain costs associated with production facilities through rate riders.
- NSP-Minnesota sells firm power and energy in wholesale markets, which are regulated by the FERC. Certain of these rates include monthly wholesale fuel cost-recovery mechanisms through prices that are indexed to NSP-Minnesota retail rates, including the monthly cost of fuel and purchased energy recovery mechanism.

Commodity Trading Operations — Pursuant to the JOA approved by the FERC, some of the commodity trading margins from NSP-Minnesota are apportioned to PSCo and SPS. Commodity trading activities are not associated with energy produced from NSP-Minnesota's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value in accordance with *ASC 815 Derivatives and Hedging*. In addition, commodity trading results include the impact of all margin-sharing mechanisms. For more information, see Note 9 to the financial statements.

Fair Value Measurements — NSP-Minnesota presents cash equivalents, interest rate derivatives, commodity derivatives and nuclear decommissioning fund assets at estimated fair values in its financial statements. Cash equivalents are recorded at cost plus accrued interest to approximate fair value. Changes in the observed trading prices and liquidity of cash equivalents, including commercial paper and money market funds, are also monitored as additional support for determining fair value and losses are recorded in earnings if fair value falls below recorded cost. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used as a primary input to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price for an identical contract in an active market, NSP-Minnesota may use quoted prices for similar contracts, or internally prepared valuation models to determine fair value. For the nuclear decommissioning fund, published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each class of security.

Types of and Accounting for Derivative Instruments — NSP-Minnesota uses derivative instruments in connection with its interest rate, utility commodity price, vehicle fuel price, short-term wholesale and commodity trading activities, including forward contracts, futures, swaps and options. All derivative instruments not designated and qualifying for the normal purchases and normal sales exception, as defined by *ASC 815 Derivatives and Hedging*, are recorded on the balance sheets at fair value as derivative instruments valuation. This includes certain instruments used to mitigate market risk for the utility operations and all instruments related to the commodity trading operations. The classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. The classification is dependent on the applicability of specific regulation.

Gains or losses on hedging transactions for the sale of energy or energy-related products are primarily recorded as a component of revenue; hedging transactions for fuel used in energy generation are recorded as a component of fuel costs; hedging transactions for

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NOTES TO FINANCIAL STATEMENTS (Continued)			

natural gas purchased for resale are recorded as a component of natural gas costs; hedging transactions for vehicle fuel costs are recorded as a component of capital projects or O&M costs; and interest rate hedging transactions are recorded as a component of interest expense. NSP-Minnesota is allowed to recover in electric or natural gas rates the costs of certain financial instruments purchased to reduce commodity cost volatility.

Cash Flow Hedges — Qualifying hedging relationships are designated as a hedge of a forecasted transaction or future cash flow (cash flow hedge). The accounting for derivatives requires that the hedging relationship be highly effective and that a company formally designate a hedging relationship to apply hedge accounting. NSP-Minnesota formally documents all hedging relationships in accordance with this guidance. The documentation includes, among other factors, the identification of the hedging instrument and the hedged transaction, as well as the risk management objectives and strategies for undertaking the hedging transaction. In addition, at inception and on a quarterly basis, NSP-Minnesota formally assesses whether the derivative instruments being used are highly effective in offsetting changes in the cash flows of the hedged items.

Changes in the fair value of a derivative designated and qualified as a cash flow hedge, to the extent effective are included in OCI, or deferred as a regulatory asset or liability based on recovery mechanisms until earnings are affected by the hedged transaction. NSP-Minnesota discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. To test the effectiveness of hedges, a hypothetical hedge is used to mirror all the critical terms of the hedged transaction and the dollar-offset method is utilized to assess the effectiveness of the actual hedge at inception and on an ongoing basis. Gains and losses related to discontinued hedges that were previously deferred in OCI or deferred as regulatory assets or liabilities will remain deferred until the hedged transaction is reflected in earnings, unless it is probable that the hedged forecasted transaction will not occur, in which case, associated deferred amounts are immediately recognized in current earnings.

Normal Purchases and Normal Sales — NSP-Minnesota enters into contracts for the purchase and sale of commodities for use in their business operations. *ASC 815 Derivatives and Hedging* requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that meet the definition of a derivative may be exempted from derivative accounting as normal purchases or normal sales.

NSP-Minnesota evaluates all of its contracts at inception to determine if they are derivatives and if they meet the normal purchases and normal sales designation requirements. None of the contracts entered into within the commodity trading operations qualify for a normal purchases and normal sales designation.

For further discussion of NSP-Minnesota's risk management and derivative activities, see Note 10 to the financial statements.

Property, Plant and Equipment and Depreciation — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and applicable interest expense. The cost of plant retired is charged to accumulated depreciation and amortization. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than units of property are charged to operating expenses as incurred. Planned major maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property. Property, plant and equipment also includes costs associated with property held for future use.

NSP-Minnesota records depreciation expense related to its plant by using the straight-line method over the plant's useful life. Actuarial and semi-actuarial life studies are performed on a periodic basis and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, for the years ended Dec. 31, 2009 and 2008 was 3.2 and 3.6 percent, respectively.

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite pretax rate to qualified construction work in progress. The amount of AFUDC capitalized as a utility construction cost is credited to nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in NSP-Minnesota's rate base for establishing utility service rates. In addition to construction-related amounts, AFUDC also is recorded to reflect returns on capital used to finance conservation programs in Minnesota.

Generally AFUDC costs are recovered from customers as the related property is depreciated. In 2003, the MPUC voted to approve

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NSP-Minnesota's MERP proposal to convert two coal-fueled electric generating plants located in the Minneapolis-St. Paul metropolitan area to natural gas and to install advanced pollution control equipment at a third coal-fired plant. These improvements are expected to significantly reduce air emissions from these facilities, while increasing the capacity at system peak by 300 MW. The first of these projects began operating in July 2007, the second of these projects began operating in May 2008 and the remaining projects began operations in March 2009, at a cumulative investment of approximately \$1 billion. The MPUC has approved a more current recovery of the financing costs related to the MERP. The in-service plant costs, including the financing costs during construction, are recovered from customers through a MERP rider resulting in a lower recognition of AFUDC.

Decommissioning — NSP-Minnesota accounts for the future cost of decommissioning, or retirement, of its nuclear generating plants through annual depreciation accruals using an annuity approach designed to provide for full rate recovery of the future decommissioning costs. The decommissioning calculation covers all expenses, including decontamination and removal of radioactive material and extends over the estimated lives of the plants. The calculation assumes that NSP-Minnesota will recover those costs through rates. The fair value of external nuclear decommissioning fund investments is determined based on quoted market prices for those or similar investments. For more information on nuclear decommissioning, see Note 14 to the financial statements.

Nuclear Fuel Expense — Nuclear fuel expense, which is recorded as NSP-Minnesota's nuclear generating plants use fuel, includes the cost of fuel used in the current period (including AFUDC), as well as future disposal costs of spent nuclear fuel, costs associated with the end-of-life fuel segments and fees assessed by the DOE for NSP-Minnesota's portion of the cost of decommissioning the DOE's fuel enrichment facility.

Nuclear Refueling Outage Costs — Effective Jan. 1, 2008, NSP-Minnesota expensed the costs associated with refueling outages as incurred at its nuclear plants. In September 2008, the MPUC authorized NSP-Minnesota to use a deferral and amortization method for the nuclear refueling O&M costs effective Jan. 1, 2008. This method amortizes refueling outage costs over the period between refueling outages to better match revenues and expenses.

Environmental Costs — Environmental costs are recorded when it is probable NSP-Minnesota is liable for the costs and the liability can be reasonably estimated. Costs may be deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. If an environmental expense is related to facilities currently in use, such as emission-control equipment, the cost is capitalized and depreciated over the life of the plant, assuming the costs are recoverable in future rates or future cash flow.

Estimated remediation costs, excluding inflationary increases, are recorded. The estimates are based on experience, an assessment of the current situation and the technology currently available for use in the remediation. The recorded costs are regularly adjusted as estimates are revised and remediation proceeds. If several designated responsible parties exist, costs are estimated and recorded only for NSP-Minnesota's expected share of the cost. Any future costs of restoring sites where operation may extend indefinitely are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses, which may include final remediation costs. Removal costs recovered in rates are classified as a regulatory liability.

Legal Costs — Litigation accruals are recorded when it is probable NSP-Minnesota is liable for the costs and the liability can be reasonably estimated. External legal fees related to settlements are expensed as incurred.

Income Taxes — NSP-Minnesota accounts for income taxes using the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. NSP-Minnesota defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. NSP-Minnesota uses the tax rates that are scheduled to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax asset will not be realized. In making such a determination, all available positive and negative evidence, including scheduled reversals of deferred tax liabilities, projected future taxable income, tax planning strategies and recent financial operations, is considered.

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded, the reversal of some temporary differences are accounted for as current income tax expense. Investment tax credits are deferred and their benefits amortized over the book depreciable lives of the related property. Utility rate regulation also has created certain regulatory assets and liabilities related to income taxes, which are summarized in Note 15 to the financial statements. For more information on income taxes, see Note 7 to the

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financial statements.

NSP-Minnesota follows the guidance in *ASC 740 Income Taxes* to measure and disclose uncertain tax positions that NSP-Minnesota has taken or expects to take in its income tax returns. In accordance with this guidance, NSP-Minnesota recognizes a tax position in its financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax expense.

NSP-Minnesota reports interest and penalties related to income taxes within the other income and interest charges sections in the statements of income.

Xcel Energy and its subsidiaries, including NSP- Minnesota, file consolidated federal income tax returns and combined and separate state income tax returns. Federal income taxes paid by Xcel Energy, as parent of the Xcel Energy consolidated group, are allocated to the Xcel Energy subsidiaries based on separate company computations of tax. A similar allocation is made for state income taxes paid by Xcel Energy in connection with combined state filings. The holding company also allocates its own net income tax benefits to its direct subsidiaries based on the positive tax liability of each company.

Use of Estimates — In recording transactions and balances resulting from business operations, NSP-Minnesota uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives, AROs, decommissioning, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. The recorded estimates are revised when better information becomes available or when actual amounts can be determined. Those revisions can affect operating results. The depreciable lives of certain plant assets are reviewed annually and revised, if appropriate.

Cash and Cash Equivalents — NSP-Minnesota considers investments in certain instruments, including commercial paper and money market funds, with a remaining maturity of three months or less at the time of purchase, to be cash equivalents.

Inventory — All inventory for NSP-Minnesota is recorded at average cost.

Regulatory Accounting — NSP-Minnesota accounts for certain income and expense items in accordance with *ASC 980 Regulated Operations*. Under this guidance:

- Certain costs, which would otherwise be charged to expense, are deferred as regulatory assets based on the expected ability to recover them in future rates; and
- Certain credits, which would otherwise be reflected as income, are deferred as regulatory liabilities based on the expectation they will be returned to customers in future rates.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the period of expected regulatory treatment. If restructuring or other changes in the regulatory environment occur, NSP-Minnesota may no longer be eligible to apply this accounting treatment and may be required to eliminate such regulatory assets and liabilities from its balance sheet. Such changes could have a material effect on NSP-Minnesota's results of operations in the period the write-off is recorded. See more discussion of regulatory assets and liabilities in Note 16 to the financial statements.

Deferred Financing Costs — Deferred financing costs, net of amortization, totaled approximately \$23.7 million and \$21.3 million at Dec. 31, 2009 and 2008, respectively. NSP-Minnesota is amortizing these financing costs over the remaining maturity periods of the related debt.

Debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses associated with refinanced debt are deferred and amortized over the life of the related new issuance, in accordance with regulatory guidelines.

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of write-offs and an allowance for bad debts. NSP-Minnesota establishes an allowance for uncollectible receivables based on a reserve policy that reflects its expected exposure to the credit risk of customers.

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Renewable Energy Credits — RECs are marketable environmental commodities that represent proof that energy was generated from eligible renewable energy sources. RECs are awarded upon delivery of the associated energy and can be bought and sold. RECs are typically used as a form of measurement of compliance to RPSs enacted by those states that are encouraging construction and consumption of renewable energy, but can also be sold separately from the energy produced. Currently, NSP-Minnesota acquires RECs from the generation or purchase of renewable power.

When RECs are acquired in the course of generation or purchase as a result of meeting load obligations, they are recorded as inventory at cost. RECs acquired for trading purposes are recorded as other investments and are also recorded at cost. The cost of RECs that are retired for compliance purposes is recorded as electric fuel and purchased power expense. The net margin on sales of RECs for trading purposes is recorded as electric utility operating revenues, net of any margin sharing requirements.

Emission Allowances — Emission allowances are recorded at cost, including the annual sulfur dioxide (SO₂) and nitrogen oxide (NO_x) emission allowance entitlement received at no cost from the Environmental Protection Agency (EPA). NSP-Minnesota follows the inventory accounting model for all allowances. The sales of allowances are reported in the operating activities section of the statements of cash flows. The net margin on sales of emission allowances is included in electric utility operating revenues as it is integral to the production process of energy and our revenue optimization strategy for our utility operations.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2009 through March 1, 2010, the date the financial statements were available for issuance. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

2. Accounting Pronouncements

Recently Adopted

Business Combinations — In December 2007, the FASB issued new guidance on business combinations which establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest; recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This new guidance is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of an entity's fiscal year that begins on or after Dec. 15, 2008. NSP-Minnesota implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its financial statements.

Noncontrolling Interests — Also in December 2007, the FASB issued new guidance on noncontrolling interests in financial statements which establishes accounting and reporting standards that require the ownership interest in subsidiaries held by parties other than the parent be clearly identified and presented in the balance sheets within equity, but separate from the parent's equity; the amount of net income attributable to the parent and the noncontrolling interest be clearly identified and presented on the face of the statement of earnings; and changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently as equity transactions. This new guidance was effective for fiscal years beginning on or after Dec. 15, 2008. NSP-Minnesota implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its financial statements.

Derivatives and Hedging Disclosures — In March 2008, the FASB issued new guidance on disclosures about derivative instruments and hedging activities which is intended to enhance disclosures to help users of the financial statements better understand how derivative instruments and hedging activities affect an entity's financial position, financial performance and cash flows. The guidance amends and expands previous disclosure requirements for derivative instruments and hedging activities, including disclosures of objectives and strategies for using derivatives, gains and losses on derivative instruments, and credit-risk-related contingent features in derivative contracts. This new guidance was effective for fiscal years and interim periods beginning after Nov. 15, 2008. NSP-Minnesota implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its financial statements. For further discussion and the required disclosures, see Note 9 to the financial statements.

Interim Fair Value Disclosures — In April 2009, the FASB issued new guidance on interim disclosures about fair value of financial instruments which requires that disclosures regarding the fair value of financial instruments be included in interim financial statements. This new guidance was effective for interim periods ending after June 15, 2009. NSP-Minnesota implemented the guidance on

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April 1, 2009, and the implementation did not have a material impact on its financial statements.

Fair Value in Inactive Markets — Also in April 2009, the FASB issued new guidance for identifying market transactions that are not orderly and determining fair value when market trading activity has decreased significantly. The new guidance emphasizes that even if there has been a significant decrease in the volume and level of market activity for an asset or liability, fair value still represents the exit price in an orderly transaction between market participants. This new guidance was effective for interim and annual periods ending after June 15, 2009. NSP-Minnesota implemented the guidance on April 1, 2009, and the implementation did not have a material impact on its financial statements.

Other-Than-Temporary Impairments — Additionally in April 2009, the FASB issued new guidance on recognition and presentation of other-than-temporary impairments which changes the method for determining whether an other-than-temporary impairment exists for debt securities, and also requires additional disclosures regarding other-than-temporary impairments. This new guidance was effective for interim and annual periods ending after June 15, 2009. NSP-Minnesota implemented the guidance on April 1, 2009, and the implementation did not have a material impact on its financial statements.

Accounting Standards Codification — In June 2009, the FASB issued *Topic 105 — Generally Accepted Accounting Principles Amendments Based on Statement of Financial Accounting Standards No. 168 — The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles (Accounting Standards Update (ASU) No. 2009-01)*, which updates the FASB ASC to state that the Codification is to be the single source of authoritative GAAP, other than the guidance put forth by the SEC. All other accounting literature not included in the Codification is to be considered non-authoritative. The updates to the Codification contained in ASU No. 2009-01 were effective for interim and annual periods ending after Sept. 15, 2009. NSP-Minnesota implemented the guidance set forth by ASU No. 2009-01, recognizing the Codification as the single source of authoritative GAAP, other than the guidance put forth by the SEC, on July 1, 2009. The implementation did not have a material impact on NSP-Minnesota's financial statements.

Postretirement Benefit Plans — In December 2008, the FASB issued new guidance on employers' disclosures about postretirement benefit plan assets. The guidance amends and expands previous disclosure requirements for plan assets of a defined benefit pension or other postretirement plan to include investment policies and strategies, major categories of plan assets, and information regarding fair value measurements. This new guidance was effective for disclosures for fiscal years ending after Dec. 15, 2009. NSP-Minnesota implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its financial statements. For further discussion and the required disclosures, see Note 8 to the financial statements.

Fair Value of Liabilities — In August 2009, the FASB issued *Fair Value Measurements and Disclosures (Topic 820) — Measuring Liabilities at Fair Value (ASU No. 2009-05)*, which updates the Codification with clarifications for measuring the fair value of liabilities. The liability-specific guidance includes clarifications and guidelines for using, when available, the most observable prices in active markets for identical liabilities or similar liabilities, or the prices of identical liabilities or similar liabilities traded as assets, rather than more complex and less observable valuation techniques and inputs such as those used in a present value model. The updates to the Codification contained in ASU No. 2009-05 were effective for interim and annual periods beginning after its August, 2009 issuance. NSP-Minnesota implemented the guidance on Sept. 1, 2009, and the implementation did not have a material impact on its financial statements.

Recently Issued

Consolidation of Variable Interest Entities — In June 2009, the FASB issued new guidance on consolidation of variable interest entities. The guidance will significantly affect various elements of consolidation under existing accounting standards, including the determination of whether an entity is a variable interest entity and whether an enterprise is a variable interest entity's primary beneficiary. This new guidance is effective for interim and annual periods beginning after Nov. 15, 2009. NSP-Minnesota does not expect the implementation of the guidance to have a material impact on its financial statements.

Fair Value Measurement Disclosures — In January 2010, the FASB issued *Fair Value Measurements and Disclosures (Topic 820) — Improving Disclosures about Fair Value Measurements (ASU No. 2010-06)*, which will update the Codification to require new disclosures for assets and liabilities measured at fair value. The requirements include expanded disclosure of valuation methodologies for Level 2 and Level 3 fair value measurements, transfers in and out of Levels 1 and 2, and gross rather than net presentation of certain changes in Level 3 fair value measurements. The updates to the Codification contained in ASU No. 2010-06 are effective for interim and annual periods beginning after Dec. 15, 2009, except for requirements related to gross presentation of certain changes in

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Level 3 fair value measurements, which are effective for interim and annual periods beginning after Dec. 15, 2010. NSP-Minnesota does not expect the implementation of the guidance to have a material impact on its financial statements.

3. Investments Accounted for by the Equity Method

In accordance with FERC regulations, NSP-Minnesota's investment in and income from all of its wholly owned subsidiaries are presented using the equity method of accounting. Subsidiaries accounted for under the equity method include:

<u>Name</u>	<u>Geographic Area</u>	<u>Economic Interest</u>
United Power & Land Co.	U.S.A.	100%
NSP Nuclear Corp.	U.S.A.	100%

Summarized Financial Information of Unconsolidated Investees:

Summarized financial information for all equity-method subsidiaries and projects, including interests owned by NSP-Minnesota was as follows:

(Thousands of dollars):

<u>Financial Position</u>			<u>Results of Operations</u>		
	<u>2009</u>	<u>2008</u>		<u>2009</u>	<u>2008</u>
Current Assets	\$ 2,929	\$ 853	Operating Revenues	\$ 8	\$ 10
Other Assets	882	897	Operating (Loss) Income	(302)	(984)
Total Assets	<u>\$ 3,811</u>	<u>\$ 1,750</u>	Net Income (Loss)	964	(1,861)
Current Liabilities	\$ 1,098	\$ —			
Other Liabilities	—	—			
Equity	<u>2,713</u>	<u>1,750</u>			
Total Liabilities and Equity	<u>\$ 3,811</u>	<u>\$ 1,750</u>			

4. Short-Term Borrowings

Commercial Paper — At Dec. 31, 2008, NSP-Minnesota had commercial paper outstanding of \$65.0 million. NSP-Minnesota has approval by the Board of Directors to issue up to \$500 million of commercial paper. The weighted average interest rate at Dec. 31, 2008 was 2.57 percent. NSP-Minnesota had no commercial paper outstanding at Dec. 31, 2009.

Money Pool — Xcel Energy and its utility subsidiaries have established a utility money pool arrangement that allows for short-term investments in and borrowings from the utility subsidiaries between each other. The Holding Company may make investments in the utility subsidiaries at market-based interest rates. However, the money pool arrangement does not allow the utility subsidiaries to make investments in the Holding Company. NSP-Minnesota has approval to borrow up to \$250 million under the arrangement. At Dec. 31, 2009 and 2008, NSP-Minnesota had money pool investments of \$7.0 million and borrowings of \$63.5 million, respectively. The weighted average interest rates at Dec. 31, 2009 and 2008 were 0.36 percent and 3.48 percent, respectively.

5. Long-Term Debt

Credit Facilities — At Dec. 31, 2009, NSP-Minnesota had the following committed credit facility in effect, in millions of dollars:

<u>Credit Facility</u>	<u>Drawn*</u>	<u>Available</u>	<u>Original Term</u>	<u>Maturity</u>
\$ 482	\$ 6	\$ 476	Five year	December 2011

* Includes direct borrowings, outstanding commercial paper and issued and outstanding letters of credit.

The line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for

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commercial paper borrowings. NSP-Minnesota has the right to request an extension of the final maturity date by one year. The maturity extension is subject to majority bank group approval.

- The credit facility has one financial covenant requiring that NSP-Minnesota's debt-to-total capitalization ratio be less than or equal to 65 percent. NSP-Minnesota was in compliance as its debt-to-total capitalization ratio was 48 percent and 50 percent at Dec. 31, 2009 and 2008, respectively. If NSP-Minnesota does not comply with the covenant, it is deemed an event of default and any outstanding amounts due under the facility can be declared due by the lender.
- The credit facility has a cross default provision that provides the borrower will be in default on its borrowings under the facility if any of its subsidiaries, comprising more than 15 percent of the assets, defaults on any of its indebtedness greater than \$50 million.
- The interest rate is based on the agent bank's prime rate or the applicable LIBOR, plus a borrowing margin as based on NSP-Minnesota's senior unsecured credit ratings from Moody, Standard & Poor and Fitch. Based on NSP-Minnesota's current credit rating the borrowing margin is 25 basis points. The commitment fees are calculated for the unused portion of the credit facility at 6 basis points for NSP-Minnesota.
- At Dec. 31, 2009, NSP-Minnesota had no direct borrowings on this line of credit; however, the credit facility was used to provide back-up support for \$5.8 million of letters of credit. At Dec. 31, 2008, NSP-Minnesota had no direct borrowings on this line of credit; however, the credit facility was used to provide back-up support for \$65.0 million of commercial paper outstanding and \$5.8 million of letters of credit.

Long-Term Borrowings

In November 2009, NSP-Minnesota issued \$300 million of 5.35 percent first mortgage bonds, series due Nov. 1, 2039. NSP-Minnesota added the net proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of the proceeds to the repayment of commercial paper and borrowings under the utility money pool arrangement incurred to fund the repayment at maturity of \$250 million of 6.875 percent unsecured senior notes due Aug. 1, 2009.

In March 2008, NSP-Minnesota issued \$500 million of 5.25 percent first mortgage bonds, series due March 1, 2018. NSP-Minnesota added the net proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of the proceeds to the repayment of commercial paper and borrowings under the utility money pool arrangement.

All property of NSP-Minnesota is subject to the lien of its first mortgage indenture. NSP-Minnesota's first mortgage indenture places certain restrictions on the amount of cash dividends it can pay Xcel Energy, the holder of its common stock. Even with these restrictions, NSP-Minnesota could have paid more than \$1.1 billion and \$1.0 billion in additional cash dividends on common stock at Dec. 31, 2009 and 2008, respectively.

Maturities of long-term debt are:

<u>(Millions of Dollars)</u>		
2010	\$	175
2011		—
2012		450
2013		—
2014		—

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6. Joint Plant Ownership

Following are the investments by NSP-Minnesota in jointly owned plants and the related ownership percentages as of Dec. 31, 2009:

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation	Construction Work in Progress	Ownership %
Sherco Unit 3	\$ 535,643	\$ 340,258	\$ 8,172	59.0
Sherco common facilities Units 1, 2 and 3	124,319	77,319	640	59.0 - 100.0
Sherco Substation	4,790	2,354	—	59.0
Grand Meadow Line and Substation	11,204	378	—	50.0
CapX2020	—	—	25,738	26.2 - 72.1
Total	<u>\$ 675,956</u>	<u>\$ 420,309</u>	<u>\$ 34,550</u>	

NSP-Minnesota is part owner of Sherco Unit 3, an 860 MW, coal-fueled electric generating unit. NSP-Minnesota is the operating agent under the joint ownership agreement. NSP-Minnesota's share of operating expenses and construction expenditures are included in the applicable utility accounts. Each of the respective owners is responsible for funding its portion of the construction costs.

7. Income Taxes

Uncertainty in Income Taxes - The FERC has not fully adopted ASC 740. Accordingly, NSP-Minnesota has recorded its unrecognized tax benefits for temporary adjustments in accounts established for accumulated deferred income taxes.

Federal Audit — NSP-Minnesota is a member of the Xcel Energy affiliated group that files a consolidated federal income tax return. In 2008, the IRS completed an examination of Xcel Energy's federal income tax returns for 2004 and 2005 (and research credits for 2003). The IRS did not propose any material adjustments for those tax years. The statute of limitations applicable to Xcel Energy's 2004 and 2005 federal income tax returns expired on Dec. 31, 2009. The IRS commenced an examination of tax years 2006 and 2007 in 2008, and this audit is expected to be completed in the first quarter of 2010. As of Dec. 31, 2009, the IRS had not proposed any material adjustments to tax years 2006 and 2007.

State Audits — NSP-Minnesota is a member of the Xcel Energy affiliated group that files consolidated state income tax returns. In 2008, the state of Minnesota concluded an income tax audit through tax year 2001. No material adjustments were proposed for this audit. As of Dec. 31, 2009, NSP-Minnesota's earliest open tax year that is subject to examination by state taxing authorities under applicable statutes of limitations is 2004. In the third quarter of 2009, Xcel Energy received a request for information from the state of Minnesota relating to tax years 2002 through 2007 in order to determine whether to undertake an audit of those years. As of Dec. 31, 2009, the state of Minnesota had not informed Xcel Energy of its intentions. There currently are no state income tax audits in progress.

Unrecognized Tax Benefits — The amount of unrecognized tax benefits was \$12.5 million and \$20.2 million on Dec. 31, 2009 and Dec. 31, 2008, respectively. A reconciliation of the beginning and ending amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	2009	2008
Balance at Jan. 1	\$ 20.2	\$ 14.3
Additions based on tax positions related to the current year	6.9	5.4
Reductions based on tax positions related to the current year	(1.4)	(0.4)
Additions for tax positions of prior years	3.6	4.9
Reductions for tax positions of prior years	(1.5)	—
Settlements with taxing authorities	(15.3)	(4.0)
Balance at Dec. 31	<u>\$ 12.5</u>	<u>\$ 20.2</u>

The unrecognized tax benefit amounts were reduced by the tax benefits associated with net operating loss (NOL) and tax credit carryovers of \$2.8 million on Dec. 31, 2009 and \$4.4 million on Dec. 31, 2008.

The unrecognized tax benefit balance included \$2.7 million and \$7.2 million of tax positions on Dec. 31, 2009 and Dec. 31, 2008, respectively, which if recognized would affect the annual effective tax rate. In addition, the unrecognized tax benefit balance included \$9.8 million and \$13.0 million of tax positions on Dec. 31, 2009 and Dec. 31, 2008, respectively, for which the ultimate deductibility

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is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

The decrease in the unrecognized tax benefit balance of \$7.7 million in 2009, was due to the resolution of certain federal audit matters, partially offset by an increase due to the addition of similar uncertain tax positions related to ongoing activity. NSP-Minnesota's amount of unrecognized tax benefits could significantly change in the next 12 months when the IRS and state audits resume. At this time, due to the uncertain nature of the audit process, it is not reasonably possible to estimate an overall range of possible change.

A reconciliation of the beginning and ending amount of the payable for interest related to unrecognized tax benefits is as follows:

(Millions of Dollars)	2009	2008
Payable for interest related to unrecognized tax benefits at Jan. 1	\$ (1.3)	\$ (1.9)
Interest income related to unrecognized tax benefits	1.0	0.6
Payable for interest related to unrecognized tax benefits at Dec. 31	<u>\$ (0.3)</u>	<u>\$ (1.3)</u>

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2009 or Dec. 31, 2008.

Other Income Tax Matters — NOL and tax credit carryforwards as of Dec. 31, 2009 and 2008 were as follows:

(Millions of Dollars)	2009	2008
Federal NOL carryforward	\$ 25.7	\$ 22.1
Federal tax credit carryforwards	25.4	18.6
State tax credit carryforwards, net of federal detriment	2.1	2.0

The federal carryforward periods expire between 2021 and 2029. The state carryforward periods expire between 2018 and 2024.

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The following reconciles such differences for the years ending Dec. 31:

	2009	2008
Federal statutory rate	35.0%	35.0%
Increases (decreases) in tax from:		
State income taxes, net of federal income tax benefit	6.2	7.6
Tax credits recognized, net of federal income tax expense	(2.7)	(1.6)
Regulatory differences — utility plant items	(1.6)	(2.3)
Resolution of income tax audits and other	1.4	(0.3)
Change in unrecognized tax benefits	(1.0)	0.1
Other, net	(0.1)	(0.2)
Effective income tax rate	<u>37.2%</u>	<u>38.3%</u>

The components of NSP-Minnesota's income tax expense for the years ending Dec. 31 were:

(Thousands of Dollars)	2009	2008
Current federal tax expense (benefit)	\$ (13,087)	\$ 18,629
Current state tax expense	18,989	29,784
Current change in unrecognized tax expense (benefit)	(4,500)	603
Deferred federal tax expense	155,233	112,582
Deferred state tax expense	30,366	23,150
Deferred tax credits	(9,542)	(4,331)
Deferred investment tax credits	(3,120)	(3,503)
Total income tax expense	<u>\$ 174,339</u>	<u>\$ 176,914</u>

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The components of deferred income tax at Dec. 31 were:

<u>(Thousands of Dollars)</u>	<u>2009</u>	<u>2008</u>
Deferred tax expense excluding items below	\$ 227,531	\$ 71,892
Amortization and adjustments to deferred income taxes on income tax regulatory assets and liabilities	(50,432)	55,322
Tax (expense) benefit allocated to other comprehensive income and other	(1,042)	4,187
Deferred tax expense	<u>\$ 176,057</u>	<u>\$ 131,401</u>

The components of net deferred tax liability (current and noncurrent) at Dec. 31 were:

<u>(Thousands of Dollars)</u>	<u>2009</u>	<u>2008</u>
Deferred tax liabilities:		
Differences between book and tax bases of property	\$ 1,453,496	\$ 1,233,678
Regulatory assets	113,364	90,622
Other	18,543	17,690
Total deferred tax liabilities	<u>\$ 1,585,403</u>	<u>\$ 1,341,990</u>
Deferred tax assets:		
Differences between book and tax bases of property	\$ 220,005	\$ 217,845
Employee benefits	62,046	62,410
Tax credit carryforward	27,519	20,546
Rate refund	26,835	19,144
Regulatory liabilities	16,478	12,927
Deferred investment tax credits	15,174	16,443
Net operating loss carryforward	9,342	6,964
Other	10,337	15,576
Total deferred tax assets	<u>\$ 387,736</u>	<u>\$ 371,855</u>
Net deferred tax liability	<u>\$ 1,197,667</u>	<u>\$ 970,135</u>

8. Benefit Plans and Other Postretirement Benefits

Pension and other postretirement benefit disclosures below generally represent Xcel Energy information unless specifically identified as being attributable to NSP-Minnesota.

Xcel Energy, which includes NSP-Minnesota, offers various benefit plans to its employees. At Dec. 31, 2009, NSP-Minnesota had 2,119 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2010. NSP-Minnesota also had an additional 222 nuclear operation bargaining employees covered under several collective-bargaining agreements, which expire at various dates through September 2010.

Effective Jan. 1, 2009, Xcel Energy and NSP-Minnesota adopted new guidance on employers' disclosures about pension and postretirement benefit plan assets. The new guidance expands employers' disclosure requirements for benefit plan assets, including investment policies and strategies, major categories of plan assets, and information regarding fair value measurements consistent with the disclosures for entities' recurring fair value measurements prescribed by *ASC 820 Fair Value Measurements*.

ASC 820 Fair Value Measurements establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring fair value. The three levels defined by the hierarchy and examples of each level are as follows:

Level 1 — Quoted prices are available in active markets for identical assets as of the reporting date. The types of assets included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as common stocks listed by the New York Stock Exchange.

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Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets included in Level 2 are typically either comparable to actively traded securities or contracts or priced with models using highly observable inputs, such as corporate bonds with pricing based on market interest rate curves and recent trades of similarly rated securities.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets included in Level 3 are those with inputs requiring significant management judgment or estimation, such as asset and mortgage backed securities, for which subjective risk-based adjustments to estimated yield and forecasted prepayments are significant inputs.

Pension Benefits

Xcel Energy, which includes NSP-Minnesota, has several noncontributory, defined benefit pension plans that cover almost all employees. Benefits are based on a combination of years of service, the employee's average pay and social security benefits. Xcel Energy's and NSP-Minnesota's policy is to fully fund the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws, into an external trust over time.

Xcel Energy and NSP-Minnesota base investment-return assumption on expected long-term performance for each of the investment types included in the pension asset portfolio and consider the actual historical returns achieved by its asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts. The historical weighted average annual return for the past 20 years for the portfolio of pension investments is 8.98 percent, which is greater than the current assumption level. The pension cost determination assumes a forecasted mix of investment types over the long term. Investment returns in 2009 were above the assumed level of 8.50 percent while returns in 2008 and 2007 were below the assumed level of 8.75 percent. Xcel Energy and NSP-Minnesota continually review the pension assumptions. In 2010, Xcel Energy will use an investment-return assumption, for all pension plans in aggregate, of 7.79 percent.

The assets are invested in a portfolio according to Xcel Energy's and NSP-Minnesota's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the allocation of assets to selected asset classes, given the long-term risk, return, and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity, however, a higher weighting in equity investments can increase the volatility in the return levels achieved by pension assets in any year.

The following table presents the target range pension asset allocations for 2009 and 2008:

	2009	2008
Domestic and international equity securities	24%	52%
Long duration fixed income securities	34	—
Short to intermediate term fixed income securities	19	25
Alternative investments	18	23
Cash	5	—
Total	100%	100%

In 2009, Xcel Energy and NSP-Minnesota engaged J.P. Morgan's Pension Advisory Group to evaluate the allocation of the total assets in the master pension trust, taking into consideration the funded status of each individual pension plan. The investment strategy employed during 2009 is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of short-to-intermediate term and long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios, and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios. The aggregate asset allocation presented in the table above for the master pension trust results from the plan-specific strategies.

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Pension Plan Assets

The following table presents, for each of the fair value hierarchy levels, pension plan assets that are measured at fair value as of Dec. 31, 2009:

(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	\$ —	\$ 221,971	\$ —	\$ 221,971
Short-term investments & money market securities	—	324,683	—	324,683
Derivatives	—	11,606	—	11,606
Government securities	—	94,949	—	94,949
Corporate bonds	—	522,403	—	522,403
Asset-backed & mortgage-backed securities	—	—	191,831	191,831
Common stock	89,260	—	—	89,260
Private equity investments	—	—	82,098	82,098
Commingled equity and bond funds	—	1,014,072	—	1,014,072
Real estate	—	—	66,704	66,704
Securities lending collateral obligation and other	—	(170,251)	—	(170,251)
Total	\$ 89,260	\$ 2,019,433	\$ 340,633	\$ 2,449,326

The following table presents the changes in Level 3 pension plan assets for the year ended Dec. 31, 2009:

(Thousands of Dollars)	Jan. 1, 2009	Realized and Unrealized Gains (Losses)	Purchases, Issuances, and Settlements (net)	Dec. 31, 2009
Asset-backed & mortgage-backed securities	\$ 244,008	\$ 151,755	\$ (203,932)	\$ 191,831
Real estate	109,289	(43,207)	622	66,704
Private equity investments	81,034	(5,682)	6,746	82,098
Total	\$ 434,331	\$ 102,866	\$ (196,564)	\$ 340,633

Benefit Obligations — A comparison of the actuarially computed pension benefit obligation and plan assets, on a combined basis, is presented in the following table:

(Thousands of Dollars)	2009	2008
Accumulated Benefit Obligation at Dec. 31	\$ 2,676,174	\$ 2,435,513
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	\$ 2,598,032	\$ 2,662,759
Service cost	65,461	62,698
Interest cost	169,790	167,881
Plan amendments	(35,341)	—
Actuarial loss (gain)	223,122	(47,509)
Benefit payments	(191,433)	(247,797)
Obligation at Dec. 31	\$ 2,829,631	\$ 2,598,032
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	\$ 2,185,203	\$ 3,186,273
Actual return (loss) on plan assets	255,556	(788,273)
Employer contributions	200,000	35,000
Benefit payments	(191,433)	(247,797)
Fair value of plan assets at Dec. 31	\$ 2,449,326	\$ 2,185,203

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Funded Status of Plans at Dec. 31:

Funded status	\$ (380,305)	\$ (412,829)
Noncurrent assets	—	15,612
Noncurrent liabilities	(380,305)	(428,441)
Net pension amounts recognized on consolidated balance sheets	<u>\$ (380,305)</u>	<u>\$ (412,829)</u>

NSP-Minnesota accrued benefit liability recorded	\$ 157,687	\$ 91,095
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NSP-Minnesota Amounts Not Yet Recognized as Components of Net Periodic**Benefit Cost:**

Net loss	\$ 530,197	\$ 454,770
Prior service cost	34,496	46,222
Total	<u>\$ 564,693</u>	<u>\$ 500,992</u>

Amounts Related to the Funded Status of the Plans Have Been Recorded as Follows Based Upon Expected Recovery in Rates:

Regulatory assets	<u>\$ 564,693</u>	<u>\$ 500,992</u>
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Measurement date	Dec. 31, 2009	Dec. 31, 2008
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Significant Assumptions Used to Measure Benefit Obligations:

Discount rate for year-end valuation	6.00%	6.75%
Expected average long-term increase in compensation level	4.00	4.00
Mortality table	RP 2000	RP 2000

At Dec. 31, 2009, Xcel Energy's pension plans, in the aggregate, had plan assets of \$2.4 billion and projected benefit obligations of \$2.8 billion. At Dec. 31, 2008, one of the pension plans had plan assets of \$259.9 million, which exceeded projected benefit obligations of \$244.3 million and all other plans in the aggregate had plan assets of \$1.9 billion and projected benefit obligations of \$2.4 billion.

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. These regulations did not require cash funding for 2008 through 2009 for the pension plans and are not expected to require cash funding in 2010.

Xcel Energy accelerated its planned 2010 contribution of \$100 million based on available liquidity, bringing its total pension contributions to \$200 million during 2009.

- Voluntary contributions were made to the PSCo Bargaining Pension Plan of \$173 million in 2009 and \$35 million in 2008.
- Voluntary contributions were made to the NCE Non-Bargaining Pension Plan of \$27 million in 2009. No voluntary contributions were made to the plan during 2008.
- Pension funding contributions for 2011, which will be dependent on several factors including, realized asset performance, future discount rate, IRS and legislative initiatives as well as other actuarial assumptions, are estimated to range between \$100 million to \$150 million.

Plan Amendments — The decrease in the projected benefit obligation for the plan amendment is due to a change in the average earnings calculation resulting from negotiations with the PSCo Bargaining Pension Plan.

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Benefit Costs — The components of net periodic pension cost (credit) are:

(Thousands of Dollars)	2009	2008
Service cost	\$ 65,461	\$ 62,698
Interest cost	169,790	167,881
Expected return on plan assets	(256,538)	(274,338)
Amortization of prior service cost	24,618	20,584
Amortization of net loss	12,455	11,156
Net periodic pension cost (credit)	<u>\$ 15,786</u>	<u>\$ (12,019)</u>

NSP-Minnesota:

Net periodic pension cost (credit)	\$ 2,891	\$ (9,034)
(Costs) credits not recognized due to effects of regulation	(2,891)	9,034
Net benefit cost recognized for financial reporting	<u>\$ —</u>	<u>\$ —</u>

Significant Assumptions Used to Measure Costs:

Discount rate for year-end valuation	6.75%	6.25%
Expected average long-term increase in compensation level	4.00	4.00
Expected average long-term rate of return on assets	8.50	8.75

Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2010 pension cost calculations will be 7.79 percent. The cost calculation uses a market-related valuation of pension assets. Xcel Energy, including NSP-Minnesota, uses a calculated value method to determine the market-related value of the plan assets. The market-related value begins with the fair market value of assets as of the beginning of the year. The market-related value is determined by adjusting the fair market value of assets to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20 percent per year.

Xcel Energy, which includes NSP-Minnesota, also maintains noncontributory, defined benefit supplemental retirement income plans for certain qualifying executive personnel. Benefits for these unfunded plans are paid out of their operating cash flows.

Defined Contribution Plans

Xcel Energy, which includes NSP-Minnesota, maintains 401(k) and other defined contribution plans that cover substantially all employees. The contributions for NSP-Minnesota were approximately \$7.5 million in 2009 and \$4.2 million in 2008.

Postretirement Health Care Benefits

Xcel Energy, which includes NSP-Minnesota, has a contributory health and welfare benefit plan that provides health care and death benefits to most Xcel Energy retirees. The former NCE discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees of NSP-Minnesota and NSP-Wisconsin who retired after 1999. Employees of the former NCE who retired after 1998 are eligible to participate in the health care program with no employer subsidy.

In 1993, Xcel Energy and NSP-Minnesota adopted accounting guidance regarding other non-pension postretirement benefits and elected to amortize the unrecognized accumulated postretirement benefit obligation (APBO) on a straight-line basis over 20 years.

Regulatory agencies for nearly all retail and wholesale utility customers have allowed rate recovery of accrued postretirement benefit costs. NSP-Minnesota transitioned to full accrual accounting for postretirement benefit costs, with regulatory differences fully amortized prior to 1997.

Plan Assets — Certain state agencies that regulate Xcel Energy's utility subsidiaries also have issued guidelines related to the funding of postretirement benefit costs. Also, a portion of the assets contributed on behalf of non-bargaining retirees has been funded into a sub-account of the pension plans. These assets are invested in a manner consistent with the investment strategy for the pension plan.

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Xcel Energy and NSP-Minnesota base investment-return assumption for the postretirement health care fund assets on expected long-term performance for each of the investment types included in the asset portfolio. The assets are invested in a portfolio according to Xcel Energy's and NSP-Minnesota's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the allocation of assets to selected asset classes, given the long-term risk, return, and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Investment-return volatility is not considered to be a material factor in postretirement health care costs.

The following table presents, for each of the fair value hierarchy levels, postretirement benefit plan assets that are measured at fair value as of Dec. 31, 2009:

(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	\$ —	\$ 165,291	\$ —	\$ 165,291
Short term investments	—	2,226	—	2,226
Derivatives	—	5,937	—	5,937
Government securities	—	1,538	—	1,538
Corporate bonds	—	60,416	—	60,416
Asset-backed & mortgage-backed securities	—	—	55,371	55,371
Preferred stock	—	540	—	540
Registered investment companies (mutual funds)	—	89,296	—	89,296
Securities lending collateral obligation and other	—	4,074	—	4,074
Total	\$ —	\$ 329,318	\$ 55,371	\$ 384,689

The following table presents the changes in Level 3 postretirement benefit plan assets for the year ended Dec. 31, 2009:

(Thousands of Dollars)	Jan. 1, 2009	Realized and Unrealized Gains	Purchases, Issuances, and Settlements (net)	Dec. 31, 2009
Asset-backed & mortgage-backed securities	\$ 78,693	\$ 4,051	\$ (27,373)	\$ 55,371

Benefit Obligations — A comparison of the actuarially computed benefit obligation and plan assets, on a combined basis, is presented in the following table:

(Thousands of Dollars)	2009	2008
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	\$ 794,597	\$ 830,315
Service cost	4,665	5,350
Interest cost	50,412	51,047
Medicare subsidy reimbursements	3,226	6,178
Plan amendments	(27,407)	—
Plan participants' contributions	13,786	13,892
Actuarial gain	(47,446)	(46,827)
Benefit payments	(62,931)	(65,358)
Obligation at Dec. 31	\$ 728,902	\$ 794,597

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Change in Fair Value of Plan Assets:

Fair value of plan assets at Jan. 1	\$ 299,566	\$ 427,459
Actual return (loss) return on plan assets	72,101	(132,226)
Plan participants' contributions	13,786	13,892
Employer contributions	62,167	55,799
Benefit payments	(62,931)	(65,358)
Fair value of plan assets at Dec. 31	<u>\$ 384,689</u>	<u>\$ 299,566</u>

Funded Status of Plans at Dec. 31:

Funded status	<u>\$ (344,213)</u>	<u>\$ (495,031)</u>
Current liabilities	(2,240)	(4,928)
Noncurrent liabilities	(341,973)	(490,103)
Net pension amounts recognized on consolidated balance sheets	<u>\$ (344,213)</u>	<u>\$ (495,031)</u>

NSP-Minnesota Amounts Not Yet Recognized as Components of Net Periodic**Benefit Cost:**

Net loss	\$ 49,444	\$ 78,140
Net prior service credit	(1,152)	—
Transition obligation	4,073	5,419
Total	<u>\$ 52,365</u>	<u>\$ 83,559</u>

Amounts Related to the Funded Status of the Plans Have Been Recorded as**Follows Based Upon Expected Recovery in Rates:**

Regulatory assets	\$ 49,240	\$ 80,105
Deferred Income taxes	1,277	1,411
Net-of-tax accumulated comprehensive income	1,848	2,043
Total	<u>\$ 52,365</u>	<u>\$ 83,559</u>

NSP-Minnesota accrued benefit liability recorded	\$ 124,657	\$ 152,792
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Measurement date	Dec. 31, 2009	Dec. 31, 2008
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Significant Assumptions Used to Measure Benefit Obligations:

Discount rate for year-end valuation	6.00%	6.75%
Mortality table	RP 2000	RP 2000

Effective Dec. 31, 2009, Xcel Energy and NSP-Minnesota reduced the initial medical trend assumption from 7.4 percent to 6.8 percent. The ultimate trend assumption remained unchanged at 5.0 percent. The period until the ultimate rate is reached is three years. Xcel Energy and NSP-Minnesota base the medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by the retiree medical plan.

A 1-percent change in the assumed health care cost trend rate would have the following effects on NSP-Minnesota:

(Thousands of Dollars)

1-percent increase in APBO components of Dec. 31, 2009	\$ 12,757
1-percent decrease in APBO components of Dec. 31, 2009	(10,801)
1-percent increase in service and interest components of the net periodic cost.	1,123
1-percent decrease in service and interest components of the net periodic cost.	(933)

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Cash Flows — The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities, as discussed previously. Xcel Energy, which includes NSP-Minnesota, contributed \$62.2 million during 2009 and \$55.6 million during 2008 and expects to contribute approximately \$45.4 million during 2010.

Plan Amendments — The decrease in the projected benefit obligation for the plan amendment is due to a change in the medical experience rate resulting from negotiations with the PSCo Bargaining Postretirement Health Care Plan.

Benefit Costs — The components of net periodic postretirement benefit cost are:

(Thousands of Dollars)	2009	2008
Service cost	\$ 4,665	\$ 5,350
Interest cost	50,412	51,047
Expected return on plan assets	(22,775)	(31,851)
Amortization of transition obligation	14,444	14,577
Amortization of prior service cost	(2,726)	(2,175)
Amortization of net loss	19,329	11,498
Net periodic postretirement benefit cost	<u>\$ 63,349</u>	<u>\$ 48,446</u>

NSP-Minnesota:

Net periodic postretirement benefit cost	13,419	13,958
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Significant Assumptions Used to Measure Costs:

Discount rate for year-end valuation	6.75%	6.25%
Expected average long-term rate of return on assets (before tax)	7.50	7.50

Benefit Payments

The following table lists the projected benefit payments for the pension and postretirement benefit plans.

(Thousands of Dollars)	Projected Pension Benefit Payments	Gross Projected Postretirement Health Care Benefit Payments	Expected Medicare Part D Subsidies	Net Projected Postretirement Health Care Benefit Payments
2010	\$ 238,929	\$ 58,738	\$ 4,901	\$ 53,837
2011	230,833	60,202	5,184	55,018
2012	234,256	60,665	5,529	55,136
2013	237,817	60,785	5,841	54,944
2014	244,160	61,260	6,075	55,185
2015-2019	1,256,824	313,040	33,598	279,442

9. Derivative Instruments

Effective Jan. 1, 2009, NSP-Minnesota adopted new guidance on disclosures about derivative instruments and hedging activities contained in *ASC 815 Derivatives and Hedging*, which requires additional disclosures regarding why an entity uses derivative instruments, the volume of an entity's derivative activities, the fair value amounts recorded to the balance sheet for derivatives, the gains and losses on derivative instruments included in the statement of income or deferred, and information regarding certain credit-risk-related contingent features in derivative contracts.

NSP-Minnesota enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to reduce risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices, as well as variances in forecasted weather. See additional information pertaining to the valuation of derivative instruments in Note 11 to the financial

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statements.

Interest Rate Derivatives — NSP-Minnesota enters into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

At Dec. 31, 2009, accumulated other comprehensive income related to interest rate derivatives included \$0.2 million of net gains expected to be reclassified into earnings during the next 12 months as the related hedged interest transactions impact earnings.

Commodity Derivatives — NSP-Minnesota enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, gas for resale, and vehicle fuel.

At Dec. 31, 2009, NSP-Minnesota had vehicle fuel contracts designated as cash flow hedges extending through December 2012. NSP-Minnesota also enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but are not designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in other comprehensive income or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. NSP-Minnesota recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the year ended Dec. 31, 2009.

At Dec. 31, 2009, accumulated other comprehensive income related to vehicle fuel cash flow hedges included \$1.8 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, NSP-Minnesota enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in income, subject to applicable customer margin-sharing mechanisms.

NSP-Minnesota had no derivative instruments designated as fair value hedges during the year ended Dec. 31, 2009. Therefore, no gains or losses from fair value hedges or related hedged transactions for the period were recognized.

The following table shows the major components of derivative instruments valuation in the balance sheets:

	2009		2008	
	Derivative Instruments Valuation - Assets	Derivative Instruments Valuation - Liabilities	Derivative Instruments Valuation - Assets	Derivative Instruments Valuation - Liabilities
(Thousands of Dollars)				
Long-term purchased power agreements	\$ 127,164	\$ 216,191	\$ 151,884	\$ 230,715
Commodity derivatives	49,534	17,998	47,973	28,522
Total	<u>\$ 176,698</u>	<u>\$ 234,189</u>	<u>\$ 199,857</u>	<u>\$ 259,237</u>

In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting contained in *ASC 815 Derivatives and Hedging*, NSP-Minnesota began recording several long-term purchased power agreements at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, NSP-Minnesota qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

Financial Impact of Qualifying Cash Flow Hedges — The impact of qualifying interest rate and vehicle fuel cash flow hedges on NSP-Minnesota's accumulated other comprehensive income, included as a component of common stockholder's equity, is detailed in the following tables:

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(Thousands of Dollars)	2009	2008
Accumulated other comprehensive income related to cash flow hedges at Jan. 1	\$ 3,053	\$ 8,704
After-tax net unrealized losses related to derivatives accounted for as hedges	(1,219)	(5,463)
After-tax net realized losses (gains) on derivative transactions reclassified into earnings	2,107	(188)
Accumulated other comprehensive income related to cash flow hedges at Dec. 31	<u>\$ 3,941</u>	<u>\$ 3,053</u>

The following table details the fair value of commodity derivatives recorded to derivative instruments valuation in the balance sheet, by category:

(Thousands of Dollars)	Dec. 31, 2009		
	Fair Value	Counterparty Netting ^(a)	Derivative Instruments Valuation
Current derivative assets			
Other derivative instruments:			
Trading commodity	\$ 19,999	\$ (11,638)	\$ 8,361
Electric commodity	23,540	1,425	24,965
Natural gas commodity	1,580	54	1,634
Total current derivative assets	<u>\$ 45,119</u>	<u>\$ (10,159)</u>	<u>\$ 34,960</u>

Noncurrent derivative assets			
Derivatives designated as cash flow hedges:			
Vehicle fuel and other commodity	\$ 85	\$ —	\$ 85
Other derivative instruments:			
Trading commodity	18,650	(4,193)	14,457
Natural gas commodity	31	1	32
Total noncurrent derivative assets	<u>\$ 18,766</u>	<u>\$ (4,192)</u>	<u>\$ 14,574</u>

(Thousands of Dollars)	Dec. 31, 2009		
	Fair Value	Counterparty Netting ^(a)	Derivative Instruments Valuation
Current derivative liabilities			
Derivatives designated as cash flow hedges:			
Vehicle fuel and other commodity	\$ 2,266	\$ —	\$ 2,266
Other derivative instruments:			
Trading commodity	17,979	(15,504)	2,475
Electric commodity	3,276	1,425	4,701
Natural gas commodity	640	54	694
Total current derivative liabilities	<u>\$ 24,161</u>	<u>\$ (14,025)</u>	<u>\$ 10,136</u>

Noncurrent derivative liabilities			
Other derivative instruments:			
Trading commodity	\$ 11,694	\$ (4,197)	\$ 7,497
Natural gas commodity	364	1	365
Total noncurrent derivative liabilities	<u>\$ 12,058</u>	<u>\$ (4,196)</u>	<u>\$ 7,862</u>

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(a) *ASC 815 Derivatives and Hedging* permits the netting of receivables and payables for derivatives and related collateral amounts when a legally enforceable master netting agreement exists between Xcel Energy and a counterparty. A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract.

The following table details the impact of derivative activity during the year ended Dec. 31, 2009, on other comprehensive income, regulatory assets and liabilities, and income:

(Thousands of Dollars)	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
	Other Comprehensive Income (Loss)	Regulatory Assets and Liabilities	Other Comprehensive Income (Loss)	Regulatory Assets and Liabilities	
Derivatives designated as cash					
flow hedges					
Interest rate	\$ (3,209)	\$	\$ (201) ^(a)	\$	\$
Electric commodity		(18,600)		(4,755) ^(c)	
Natural gas commodity		(811)		8,915 ^(d)	(6,951) ^(d)
Vehicle fuel and other commodity	1,147		3,766 ^(e)		
Total	<u>\$ (2,062)</u>	<u>\$ (19,411)</u>	<u>\$ 3,565</u>	<u>\$ 4,160</u>	<u>\$ (6,951)</u>
Other derivative instruments					
Trading commodity					7,857 ^(b)
Electric commodity		20,607		(343) ^(c)	
Natural gas commodity		(373)		980 ^(d)	
Other					(160) ^(b)
Total	<u>\$ —</u>	<u>\$ 20,234</u>	<u>\$ —</u>	<u>\$ 637</u>	<u>\$ 7,697</u>

(a) Recorded to interest charges.

(b) Recorded to electric operating revenues. Portions of these gains and losses are shared with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(c) Recorded to electric fuel and purchased power; these derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(d) Recorded to cost of natural gas sold and transported; these derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(e) Recorded to other operating and maintenance expenses.

At Dec. 31, 2009, commodity derivatives recorded to derivative instruments valuation included derivative contracts with gross notional amounts of approximately 34,374,000 megawatt hours (MwH) of electricity, 9,777,000 MMBtu of natural gas and 2,021,000 gallons of vehicle fuel. These amounts reflect the gross notional amounts of futures, forwards and financial transmission rights and are not reflective of net positions in the underlying commodities. Notional amounts for options are also included on a gross basis, but are weighted for the probability of exercise.

Credit Related Contingent Features — Contract provisions of the derivative instruments that NSP-Minnesota enters into may require the posting of collateral or settlement of the contracts for various reasons, including if NSP-Minnesota is unable to maintain its credit rating. If the credit rating of NSP-Minnesota at Dec. 31, 2009 were downgraded below investment grade, no contracts underlying NSP-Minnesota's derivative liabilities would require the posting of collateral or contract settlement upon the downgrade.

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Certain of NSP-Minnesota's derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that NSP-Minnesota's ability to fulfill its contractual obligations is reasonably expected to be impaired. As of Dec. 31, 2009, NSP-Minnesota had no collateral posted related to adequate assurance clauses in derivative contracts.

10. Financial Instruments

The estimated Dec. 31 fair values of NSP-Minnesota's recorded financial instruments are as follows:

(Thousands of Dollars)	2009		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Nuclear decommissioning fund	\$ 1,248,739	\$ 1,248,739	\$ 1,075,294	\$ 1,075,294
Other investments	695	695	725	725
Long-term debt, including current portion	3,013,178	3,238,854	2,962,749	3,100,223

The fair value of cash and cash equivalents, notes and accounts receivable and notes and accounts payable are not materially different from their carrying amounts. The fair value of NSP-Minnesota's nuclear decommissioning fund is based on published trading data and pricing models, generally using the most observable inputs available for each class of security. The fair value of NSP-Minnesota's other investments are estimated based on quoted market prices for those or similar investments. The fair value of NSP-Minnesota's long-term debt is estimated based on the quoted market prices for the same or similar issues, or the current rates for debt of the same remaining maturities and credit quality.

The fair value estimates presented are based on information available to management as of Dec. 31, 2009 and 2008. These fair value estimates have not been comprehensively revalued for purposes of these financial statements since that date, and current estimates of fair values may differ significantly.

Letters of Credit

NSP-Minnesota uses letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2009 and 2008, there were \$6.9 million letters of credit outstanding. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

11. Fair Value Measurements

Effective Jan. 1, 2008, NSP-Minnesota adopted new guidance for recurring fair value measurements contained in *ASC 820 Fair Value Measurements and Disclosures* which provides a single definition of fair value and requires enhanced disclosures about assets and liabilities measured at fair value. A hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value was established by this guidance. The three levels in the hierarchy and examples of each level are as follows:

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

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

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value of financial transmission rights.

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NSP-Minnesota continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of NSP-Minnesota's own credit risk when determining the fair value of commodity derivative liabilities, the impact of considering credit risk was immaterial to the fair value of commodity derivative assets and liabilities presented in the balance sheets.

The following tables present, for each of these hierarchy levels, NSP-Minnesota's assets and liabilities that are measured at fair value on a recurring basis:

(Thousands of Dollars)	Dec. 31, 2009				
	Level 1	Level 2	Level 3	Counterparty Netting	Net Balance
Assets					
Nuclear decommissioning fund					
Cash equivalents	\$ —	\$ 28,134	\$ —	\$ —	\$ 28,134
Debt securities	—	545,503	93,107	—	638,610
Equity securities	581,995	—	—	—	581,995
Commodity derivatives	—	22,481	41,404	(14,351)	49,534
Total	<u>\$ 581,995</u>	<u>\$ 596,118</u>	<u>\$ 134,511</u>	<u>\$ (14,351)</u>	<u>\$ 1,298,273</u>

Liabilities					
Commodity derivatives	\$ —	\$ 22,052	\$ 14,167	\$ (18,221)	\$ 17,998

(Thousands of Dollars)	Dec. 31, 2008				
	Level 1	Level 2	Level 3	Counterparty Netting	Net Balance
Assets					
Nuclear decommissioning fund					
Cash equivalents	\$ —	\$ 8,449	\$ —	\$ —	\$ 8,449
Debt securities	—	491,486	109,423	—	600,909
Equity securities	465,936	—	—	—	465,936
Commodity derivatives	—	17,039	38,207	(7,273)	47,973
Total	<u>\$ 465,936</u>	<u>\$ 516,974</u>	<u>\$ 147,630</u>	<u>\$ (7,273)</u>	<u>\$ 1,123,267</u>

Liabilities					
Commodity derivatives	\$ —	\$ 21,509	\$ 14,960	\$ (7,947)	\$ 28,522

The following table presents the changes in Level 3 recurring fair value measurements:

(Thousands of Dollars)	Dec. 31,			
	2009		2008	
	Commodity Derivatives, Net	Nuclear Decommissioning Fund	Commodity Derivatives, Net	Nuclear Decommissioning Fund
Balance at Jan. 1	\$ 23,247	\$ 109,423	\$ 15,345	\$ 108,656
Purchases, issuances, and settlements, net	(476)	(28,356)	(1,585)	12,198
Transfers into (out of) Level 3	700	—	(2,578)	—
(Losses) gains recognized in earnings	(3,115)	—	496	—
Gains (losses) recognized as regulatory assets and liabilities	6,881	12,040	11,569	(11,431)
Balance at Dec. 31	<u>\$ 27,237</u>	<u>\$ 93,107</u>	<u>\$ 23,247</u>	<u>\$ 109,423</u>

Losses on Level 3 commodity derivatives recognized in earnings for the year ended Dec. 31, 2009, include \$5.7 million of net unrealized gains relating to commodity derivatives held at Dec. 31, 2009. Gains on Level 3 commodity derivatives recognized in earnings for the year ended Dec. 31, 2008, include \$2.9 million of net unrealized gains relating to commodity derivatives held at

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Dec. 31, 2008. Realized and unrealized gains and losses on commodity trading activities are included in electric revenues. Realized and unrealized gains and losses on non-trading derivative instruments are recorded in other comprehensive income or deferred as regulatory assets and liabilities. The classification as a regulatory asset or liability is based on the commission approved regulatory recovery mechanisms. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a component of a nuclear decommissioning regulatory asset.

12. Rate Matters

NSP-Minnesota

Pending and Recently Concluded Regulatory Proceedings — Minnesota Public Utilities Commission (MPUC)

Base Rate

NSP-Minnesota Electric Rate Case — In November 2008, NSP-Minnesota filed a request with the MPUC to increase Minnesota electric rates by \$156 million annually. This request was later modified to \$136 million.

In September 2009, the MPUC voted to approve a rate increase of approximately \$91.4 million. As part of its decision, the MPUC approved a 10-year life extension of the Prairie Island nuclear plant for purposes of determining depreciation and decommissioning expenses, effective Jan. 1, 2009. This decision reduced NSP-Minnesota's overall revenue deficiency by approximately \$40 million, while at the same time reducing expense accruals by a corresponding amount. A summary of the key terms is listed below:

	<u>Revised Request</u>	<u>Approved</u>
Rate increase	\$136 million	\$91 million
Return on equity	11.0%	10.88%
Equity ratio	52.5%	52.5%
Electric rate base	\$4.1 billion	\$4.1 billion
Depreciation life extension for Prairie Island nuclear plant	0 years	10 years

The written order was issued Oct. 23, 2009. As of December 2009, NSP-Minnesota recorded a customer refund of approximately \$39.7 million to reflect the difference between interim rates that were implemented Jan. 2, 2009 and the amount approved by the MPUC.

NSP-Minnesota Gas Rate Case — In November 2009, NSP-Minnesota filed a request with the MPUC to increase Minnesota gas rates by \$16.2 million for 2010, which represents a 2.8 percent overall increase in customer bills. This request is based on a ROE of 11 percent, an equity ratio of 52.46 percent and a rate base of \$441 million. NSP-Minnesota also requested an additional increase of \$3.45 million, for recovery of pension funding costs effective Jan. 1, 2011 to comply with federal law. In December 2009, the MPUC voted to approve an interim rate increase of \$11.1 million, subject to refund. These rates went into effect on Jan. 11, 2010. The procedural schedule is listed below and a decision is expected in the fall of 2010.

- Intervenor direct testimony on May 3, 2010;
- NSP-Minnesota rebuttal testimony on June 2, 2010;
- Surrebuttal testimony on June 15, 2010;
- Evidentiary hearings on June 21-25, 2010;
- Initial briefs on July 27, 2010;
- Reply briefs and proposed findings on Aug. 19, 2010; and
- ALJ report on Oct. 1, 2010.

Electric, Purchased Gas and Resource Adjustment Clauses

Transmission Cost Recovery (TCR) Rider — The MPUC has approved a TCR rider, which allows annual adjustments to retail electric rates to provide recovery of incremental transmission investments between rate cases. The MPUC approved a rider request to recover approximately \$14 million in 2009. NSP-Minnesota has a request pending seeking recovery of \$12.1 million in 2010. The Office of

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Energy Security (OES) recommended disallowance of \$1.7 million of plant costs because one project was over budget and also recommended that the Brookings line, which is subject to dispute at FERC on cost allocation not be recovered through the rider at this time. The request is pending MPUC action.

Renewable Energy Standard (RES) Rider — The MPUC has approved a rider to recover the costs for utility-owned projects implemented in compliance with the RES. In 2009, the MPUC approved the RES rider request to recover approximately \$22 million in 2009. In September 2009, NSP-Minnesota submitted its proposed RES rider, seeking to recover \$45.6 million in 2010. The OES expressed concerns because some of the projected costs were slightly higher than the levels included in NSP-Minnesota's certificate filings and requested additional information, which has been provided. The request is pending MPUC action.

Metropolitan Emissions Reduction Project (MERP) Rider — The MPUC authorized NSP-Minnesota to recover costs related to environmental improvement projects amounting to approximately \$113.7 million in 2009 through the MERP rider. In December 2009, the MPUC authorized a new rate adjustment, which will recover approximately \$116.7 million in 2010.

Mercury Cost Rider — The MPUC has approved mercury control plans for reducing mercury emissions at the Sherco Unit 3 and A. S. King plants. A sorbent injection control system was put into service at Sherco Unit 3 in December 2009, with installation at A. S. King scheduled to be completed in December 2010. Currently, the estimated project costs are approximately \$6.6 million for these two units, and the MPUC authorized NSP-Minnesota to collect the 2010 revenue requirement associated with these projects, which is approximately \$3.5 million, from customers through a mercury rider in 2010. On Dec. 21, 2009, NSP-Minnesota filed the plans for mercury control at Sherco Units 1 and 2 with the MPUC and Minnesota Pollution Control Agency (MPCA). Assuming these plans are approved, NSP-Minnesota expects to file for recovery of the costs to implement these plans through the mercury cost rider. The plan proposes a flexible program of testing and monitoring as new technology emerges and federal regulations change over the next several years. The plan calls for the addition of sorbent injection by the statutory deadline of the end of 2014. The MPCA has six months to review the plan.

State Energy Policy (SEP) Rider — In September 2009, the MPUC approved NSP-Minnesota proposed rider to recover approximately \$2.5 million from its electric customers and \$0.1 million from its natural gas customers to recover costs related to SEP mandates and a cast iron natural gas pipe replacement project to reduce greenhouse gas (GHG) emissions. The revised SEP rate recovery factors were placed into effect in October 2009.

Energy Innovation Corridor (EIC) Initiative — In December 2009, NSP-Minnesota filed a request with the MPUC for approval of specific projects totaling \$15 million including a \$2 million deferral request. The EIC initiative will be a first-of-its-kind clean energy and transportation model in an established urban center in the upper Midwest. The 2009 legislation authorized rider cost recovery for MPUC approved projects, including NSP-Minnesota's costs to relocate its facilities along the transportation corridor. Rider cost recovery is also authorized for MPUC approved EIC projects that demonstrate the best energy efficiency management practices and the installation of innovative and sustainable energy technologies and programs for transforming a mature urban center into a national model for the future development of transportation and energy corridors. The EIC initiative will advance critical local, state, regional and federal efforts to invest in energy efficiency, transportation electrification, renewable energy and smart grid technology. MPUC action is pending.

Annual Automatic Adjustment Report for 2007/2008 — In September 2008, NSP-Minnesota filed its annual automatic adjustment reports for July 1, 2007 through June 30, 2008. During that time period, \$848.5 million in fuel and purchased energy costs, including \$258.8 million of Midwest Independent Transmission Operator, Inc. (MISO) charges, were recovered from Minnesota electric customers through the fuel clause adjustment (FCA). In addition, approximately \$680 million of purchased natural gas and transportation costs were recovered through the purchased gas adjustment (PGA). In February 2010, the MPUC voted to accept the 2008 natural gas annual automatic adjustment report.

Annual Automatic Adjustment Report for 2008/2009 — In September 2009, NSP-Minnesota filed its annual automatic adjustment reports for July 1, 2008 through June 30, 2009. During that time period, \$803.6 million in fuel and purchased energy costs were recovered from Minnesota electric customers through the FCA. In addition, approximately \$499.4 million of purchased natural gas and transportation costs were recovered through the PGA. Comments are due in May 2010 on NSP-Minnesota's 2008/2009 electric and natural gas annual automatic adjustment reports. The request is pending MPUC action.

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Conservation Incentive Filing — In July 2009, NSP-Minnesota filed its proposed incentive plan for achieving significantly higher DSM goals. The incentive would allow for sharing of savings of up to 15 percent of the net present value of benefits, depending on the level of savings achieved. In December 2009, the MPUC approved the proposed shared savings model. The plan would allow NSP-Minnesota to earn a higher incentive than under the previous method if it achieves the higher goals established by the OES. The amount of the incentive increases to the extent that NSP-Minnesota cost-effectively exceeds the goal. A written order was issued in January 2010.

Gas Meter Module Failures — Approximately 8,700 customers in the St. Cloud and East Grand Forks areas of Minnesota and about 4,000 customers in the Fargo, N.D. area were under billed for a period of time during the 2007-2008 heating season due to the failure of the automated meter reading (AMR) module installed on their natural gas meters. While the modules failed to register usage, the meters continued to function.

Pursuant to the NDPSC-approved plan, which provided customers with a \$50 service quality credit for each customer experiencing a module failure, NSP-Minnesota began implementing the service quality credits and the rebilling of remaining North Dakota customers in June 2009. In total, NSP-Minnesota rebilled North Dakota customers approximately \$1.5 million for the estimated gas usage during the module failure period.

In July 2009, NSP-Minnesota filed with the MPUC a withdrawal of its request to rebill Minnesota customers experiencing a module failure, which the MPUC approved in October 2009. NSP-Minnesota completed the customer refunds in January 2010. In November 2009, NSP-Minnesota completed its dispute resolution with its provider of the AMR modules and meter reading services, and filed a summary of the resolution and proposed disposition of any proceeds with the MPUC. MPUC action is pending. NSP-Minnesota has determined that a number of AMR modules designed for commercial customers are defective and as a result broadened its efforts to evaluate the performance of both gas and electric AMR modules.

Annual Review of Remaining Lives — In February 2009, NSP-Minnesota filed a petition with the MPUC requesting an increase in proposed service lives, salvage rates and resulting depreciation rates for its electric and gas production facilities and a depreciation study for other gas and electric assets, effective Jan 1, 2009. In addition, the OES recommended a 10-year lengthening of depreciation life of the Prairie Island nuclear plant. In July 2009, the MPUC approved the proposed service lives, salvage rates, and resulting depreciation rates effective Jan. 1, 2009, for plant in service, with the exception of the Prairie Island nuclear plant. In the NSP-Minnesota electric rate case, the MPUC extended the depreciation life of the Prairie Island nuclear plant by 10 years beyond the current license life in light of NSP-Minnesota's application to extend the life of its nuclear plants by 20 years.

Nuclear Decommissioning Expenses — In June 2009, the MPUC issued its order in its review of NSP-Minnesota's 2009 nuclear plant decommissioning accruals. The order extended the decommissioning life for the Prairie Island nuclear plant by 10 years. The order reduced the amount of future nuclear decommissioning expenses that must be collected from customers from \$32 million to zero, effective Jan. 1, 2009.

In August 2009, NSP-Minnesota filed a proposal with the MPUC to provide one-time refunds to return to customers their contributions of \$22.8 million made to the external escrow decommissioning fund for the Monticello nuclear plant, which the MPUC approved in November 2009. NSP-Minnesota began refunding the excess escrow to customers in February 2010.

Pending and Recently Concluded Regulatory Proceedings — South Dakota Public Utilities Commission (SDPUC)

South Dakota Electric Rate Case — In June 2009, NSP-Minnesota filed a request with the SDPUC to increase South Dakota electric rates by \$18.6 million annually, or 12.7 percent. This proposed increase includes approximately \$2.9 million in revenues currently recovered through automatic recovery mechanisms. Thus, the requested increase, net of current automatic recovery mechanisms, is approximately \$15.7 million or 10.7 percent. The request is based on a 2008 historic test year adjusted for known and measurable changes in rate base and O&M expenses, an electric rate base of \$282 million, a requested ROE of 11.25 percent, and an equity ratio of 51.63 percent.

On Jan. 5, 2010, the South Dakota Commission approved a settlement agreement, which increases electric base rates by \$10.9 million. The primary difference between the approved rate increase and requested amount was due to a lower ROE and the use of a 20-year life for the Prairie Island nuclear plant, which reduced the revenue deficiency and expense accruals by a corresponding amount. New rates

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were effective on Jan. 18, 2010.

Pending and Recently Concluded Regulatory Proceedings — FERC

Revenue Sufficiency Guarantee (RSG) Charges — The MISO tariff charges certain market participants a real-time RSG charge, which is designed to ensure that any generator scheduled or dispatched by MISO will receive no less than its offer price for start-up, no-load and incremental energy. A proposal in 2005 by MISO to refine the RSG charge initiated protracted proceedings. In the subsequent compliance proceeding, the FERC has issued numerous orders, attempting to refine and clarify the RSG charge. With the issuance of these orders, the FERC has directed certain refunds to market participants, but has subsequently refined or waived various refund requirements. The FERC granted rehearing in part of certain earlier orders directing refunds to correct a rate mismatch in the RSG charge.

In August 2007, numerous parties filed complaints against MISO, arguing that the allocation of the RSG charge (only to certain market participants actually withdrawing energy) was unjust, unreasonable, and unduly discriminatory. After protracted proceedings, the FERC found in November 2008 that the RSG charge was unjust and unreasonable, and directed refunds. In May 2009, FERC granted rehearing in part regarding the applicability of refunds for the RSG charges. Specifically, the FERC determined that the refund-effective date is November 2008, the date of the FERC order determining that the allocation to market participants of the RSG charges was unjust and unreasonable.

The FERC directed MISO to implement an interim RSG cost allocation to be effective starting in August 2007. The FERC further directed MISO to submit a complete and final proposal, to be implemented on a prospective basis after the commencement of the MISO's ASMs in January 2009. In February 2009, MISO submitted a filing to implement the new RSG rate design; however, the FERC has not yet rendered a final decision to implement the new rate design. In August 2009, the FERC issued an order in which it invalidated numerous exemptions to the RSG that had previously been utilized by MISO through its business practice manuals. Several parties have sought rehearing of the order and a final FERC decision is still pending.

Xcel Energy is a party to each of the relevant RSG-related proceedings. Each of the relevant RSG-related orders has been the subject of requests for rehearing at the FERC and petitions for review filed at the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). The separate RSG proceedings have proceeded in parallel at the FERC, and the most recent orders are subject to pending requests for rehearing. The D.C. Circuit proceedings are being held in abeyance pending final action in the FERC proceedings.

FERC Section 5 Rate Cases for Interstate Gas Pipelines — In November 2009, the FERC approved orders initiating rate investigations under Section 5 of the Natural Gas Act (NGA) against Northern Natural Gas Company (NNG) and Great Lakes Gas Transmission Company (GLGT). NSP-Minnesota and NSP-Wisconsin are together the largest customer on NNG, holding \$41 million per year of maximum rate storage and transportation contracts.

According to the FERC orders, FERC staff concluded, based on a review of the financial information filed with the FERC by the pipelines, that each of the pipelines are substantially over-recovering their cost of service and earning excessive ROEs. The orders require the pipelines to file full cost and revenue studies, and the matters were set for hearing before an ALJ on an expedited basis. If the FERC orders the pipelines to reduce their transportation and storage rates, the rate reductions and any associated refunds would be reflected in the purchased gas and electric fuel cost adjustment mechanisms of the Xcel Energy utility subsidiaries.

Xcel Energy has filed an intervention as part of a group of similarly-situated GLGT shippers in the GLGT Section 5 case, and filed to intervene individually in the NNG Section 5 rate case. The FERC ALJ conducted a pre-hearing conference on Jan. 12, 2010 and established the procedural schedule for the proceedings. If fully litigated, the Section 5 rate cases can be expected to go to hearings before the ALJ beginning Aug. 2, 2010. An initial decision must be issued by Nov. 11, 2010.

13. Commitments and Contingent Liabilities

Capital Commitments — As of Dec. 31, 2009, the estimated cost of the capital expenditure programs and other capital requirements of NSP-Minnesota is approximately \$1.2 billion in 2010, \$1.2 billion in 2011 and \$1.0 billion in 2012. NSP-Minnesota's capital forecast includes the following major projects.

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Nuclear Capacity Increases and Life Extension — NSP-Minnesota is seeking a 20-year license renewal for the Monticello and Prairie Island nuclear plants. A renewed operating license was approved and issued for Monticello by the NRC in November 2006 licensing the plant to operate until 2030, and the MPUC order approving the spent fuel storage capacity needed to support plant operations until 2030 went into effect in June 2007. The application to renew Prairie Island's operating licenses was submitted to the NRC in April 2008 and the application for a certificate of need (CON) for additional spent fuel storage capacity to support 20 additional years of plant operation was approved by the MPUC in December 2009. Final state and federal approvals are expected in 2010.

NSP-Minnesota is pursuing capacity increases of Monticello and Prairie Island that will total approximately 235 MW, to be implemented, if approved, between 2010 and 2015. The life extension and capacity increase for Prairie Island Unit 2 is contingent on replacement of Unit 2's original steam generators, currently planned during the refueling outage in 2013. Total capital investment for these activities is estimated to be over \$1 billion between 2010 and 2015. NSP-Minnesota submitted the CON and site permit applications for Monticello's power uprate in the first quarter of 2008 and the CON and site permit applications for Prairie Island's power uprate in the second quarter of 2008. The MPUC approved the Monticello power uprate CON and site permit in December 2008 and the Prairie Island power uprate CON and site permit in December 2009.

Wind Generation — NSP-Minnesota is investing approximately \$900 million over three years for a 201 MW project in southwestern Minnesota, called the Nobles Wind Project, and a 150 MW project in southeastern North Dakota, called the Merricourt Wind Project. These projects are expected to be operational by the end of 2010 and 2011, respectively. NSP-Minnesota has received regulatory approval for the projects, and has requested recovery of eligible costs beginning in 2010.

CapX 2020 — In 2006, CapX 2020, an alliance of electric cooperatives, municipalities and investor-owned utilities in the upper Midwest, including Xcel Energy, announced that it had identified several groups of transmission projects that proposed to be complete by 2020. Group 1 project investments are expected to total approximately \$1.7 billion, with major construction targeted to begin in 2010 and ending three to five years later. Xcel Energy's investment is expected to be approximately \$900 million depending on the route and configuration approved by the MPUC and the PSCW. Approximately 75 percent of the 2010 capital expenditures and return on investment for transmission projects are expected to be recovered under an NSP-Minnesota TCR tariff rider mechanism authorized by Minnesota legislation, as well as a similar TCR mechanism passed in South Dakota. Cost-recovery by NSP-Wisconsin is expected to occur through the biennial PSCW rate case process.

The capital expenditure programs of NSP-Minnesota are subject to continuing review and modification. Actual utility construction expenditures may vary from the estimates due to changes in electric and natural gas projected load growth regulatory decisions, the desired reserve margin and the availability of purchased power, as well as alternative plans for meeting NSP-Minnesota's long-term energy needs. In addition, NSP-Minnesota's ongoing evaluation of compliance with future requirements to install emission-control equipment and merger, acquisition and divestiture opportunities to support corporate strategies may impact actual capital requirements.

Fuel Contracts — NSP-Minnesota has contracts providing for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2010 and 2028. In addition, NSP-Minnesota may be required to pay additional amounts depending on actual quantities shipped under these agreements. The potential risk of loss, in the form of increased costs from market price changes in fuel, is mitigated through the cost-rate adjustment mechanisms, which provide for pass through of most fuel, storage and transportation costs.

The estimated minimum purchases for NSP-Minnesota under these contracts as of Dec. 31, 2009, is as follows:

<u>(Millions of Dollars)</u>	<u>2009</u>
Coal	\$ 599.1
Nuclear fuel	598.3
Natural gas supply	278.0
Gas storage and transportation	950.1

Purchased Power Agreements — NSP-Minnesota has entered into agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages and meet operating reserve obligations. NSP-Minnesota has various pay-for-performance contracts with expiration dates

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through the year 2033. In general, these contracts provide for capacity payments, subject to meeting certain contract obligations and energy payments based on actual power taken under the contracts. Certain contractual payment obligations are adjusted based on indices. However, the effects of these price adjustments are mitigated through cost-of-energy rate adjustment mechanisms.

At Dec. 31, 2009, the estimated future payments for capacity, accounted for as executory contracts, that NSP-Minnesota is obligated to purchase, subject to availability, were as follows:

<u>(Millions of Dollars)</u>	
2010	\$ 110.7
2011	110.0
2012	109.2
2013	111.8
2014	114.3
2015 and thereafter	319.8
Total *	<u>\$ 875.8</u>

* Includes amounts allocated to NSP-Wisconsin through intercompany charges.

Leases — NSP-Minnesota leases a variety of equipment and facilities used in the normal course of business, which are accounted for as operating leases. Total rental expense under operating lease obligations was approximately \$76.2 million and \$70.7 million for 2009 and 2008, respectively. Included in total rental expense were purchase power agreement payments of \$56.2 million and \$48.6 million in 2009 and 2008, respectively.

Included in the future commitments under operating leases are estimated future payments under purchase power agreements that have been accounted for as operating leases in accordance with *ASC 840 Leases*. Future commitments under operating leases are:

<u>(Millions of Dollars)</u>	<u>Other Operating Leases</u>	<u>Purchased Power Agreement Operating Leases ^(a) ^(b)</u>	<u>Total Operating Leases</u>
2010	\$ 10.5	\$ 53.1	\$ 63.6
2011	11.2	54.0	65.2
2012	9.5	55.0	64.5
2013	8.9	55.9	64.8
2014	8.5	56.8	65.3
Thereafter	51.1	674.1	725.2

^(a) Amounts not included in purchase power agreement estimated future payments above.

^(b) Purchase power agreement operating leases contractually expire through 2025.

Environmental Contingencies

NSP-Minnesota has been, or is currently, involved with the cleanup of contamination from certain hazardous substances at several sites. In many situations, NSP-Minnesota believes it will recover some portion of these costs through insurance claims. Additionally, where applicable, NSP-Minnesota is pursuing, or intends to pursue, recovery from other PRPs and through the rate regulatory process. New and changing federal and state environmental mandates can also create added financial liabilities for NSP-Minnesota, which are normally recovered through the rate regulatory process. To the extent any costs are not recovered through the options listed above, NSP-Minnesota would be required to recognize an expense.

Site Remediation — NSP-Minnesota must pay all or a portion of the cost to remediate sites where past activities of NSP-Minnesota or other parties have caused environmental contamination. Environmental contingencies could arise from various situations including sites of former manufactured gas plants operated by NSP-Minnesota, its predecessors or other entities; and third party sites, such as

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landfills, to which NSP-Minnesota is alleged to be a PRP that sent hazardous materials and wastes. At Dec. 31, 2009, the liability for the cost of remediating these sites was estimated to be \$0.3 million, of which \$0.2 million was considered to be a current liability.

Asbestos Removal — Some of NSP-Minnesota's facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or removed. NSP-Minnesota has recorded an estimate for final removal of the asbestos as an ARO. See additional discussion of asset retirement obligations (AROs) below. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is immaterial and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Other Environmental Requirements

EPA GHG Endangerment Finding — On Dec. 7, 2009, in response to the U. S. Supreme Court's decision in *Massachusetts v. EPA*, 549 U. S. 497 (2007), the EPA issued its "endangerment" finding that GHG emissions endanger public health and welfare and that emissions from motor vehicles contribute to the GHGs in the atmosphere. This endangerment finding creates a mandatory duty for the EPA to regulate GHGs from light duty vehicles. The EPA has proposed to finalize GHG efficiency standards for light duty vehicles by spring 2010. Thereafter, the EPA anticipates phasing-in permit requirements and regulation of GHGs for large stationary sources, such as power plants, in calendar year 2011.

Clean Air Interstate Rule (CAIR) — In March 2005, the EPA issued the CAIR to further regulate SO₂ and NO_x emissions. The objective of CAIR is to cap emissions of SO₂ and NO_x in the eastern United States, including Minnesota. In response to the decisions by the D.C. Circuit Court of Appeals vacating but reinstating CAIR while the EPA develops revised regulations, the EPA has indicated that a CAIR replacement rule will be proposed in early 2010 with finalization planned for early 2011.

As currently written, CAIR has a two-phase compliance schedule, beginning in 2009 for NO_x and 2010 for SO₂, with a final compliance deadline in 2015 for both emissions. Under CAIR, each affected state will be allocated an emissions budget for SO₂ and NO_x that will result in significant emission reductions. It will be based on stringent emission controls and forms the basis for a cap and trade program. State emission budgets or caps decline over time. States can choose to implement an emissions reduction program based on the EPA's proposed model program, or they can propose another method, which the EPA would need to approve.

On Nov. 3, 2009, the EPA published a rule staying the effectiveness of CAIR in Minnesota effective Dec. 3, 2009. Cost estimates are therefore not included at this time for NSP-Minnesota.

Clean Air Mercury Rule (CAMR) — In March 2005, the EPA issued the CAMR, which regulated mercury emissions from power plants. In February 2008, the U. S. Court of Appeals for the District of Columbia vacated CAMR, which impacts federal CAMR requirements, but not necessarily state-only mercury legislation and rules. The EPA has agreed to finalize MACT emission standards for all hazardous air pollutants from electric utility steam generating units by November 2011 to replace CAMR. Xcel Energy, the parent company of NSP-Minnesota, anticipates that the EPA will require affected facilities to demonstrate compliance within 18 to 36 months thereafter.

Minnesota Mercury Legislation — In May 2006, the Minnesota legislature enacted the Mercury Emissions Reduction Act of 2006 (Act) providing a process for plans, implementation and cost recovery for utility efforts to curb mercury emissions at certain power plants. For NSP-Minnesota, the Act covers units at the A. S. King and Sherco generating facilities. Xcel Energy installed and is operating and maintaining continuous mercury emission monitoring systems at these generating facilities.

In September 2006, NSP-Minnesota filed a request with the MPUC for recovery of up to \$6.3 million of certain environmental improvement costs recoverable under the Act. In January 2007, the MPUC approved this request to defer these costs as a regulatory asset with a cap of \$6.3 million. In November 2008, NSP-Minnesota filed a request with the MPUC to reflect its requested recovery of these emission reduction compliance costs incurred through 2009 in the NSP-Minnesota electric rate case. In June 2009, NSP-Minnesota received an order from the MPUC closing the docket to correspond with the inclusion of costs in the electric rate case. The recovery of the costs was allowed as part of the rate case.

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In November 2008, the MPUC approved and ordered the implementation of the Sherco Unit 3 and A. S. King mercury emission reduction plans. A sorbent injection control system was installed at Sherco Unit 3 in December 2009, with installation at A. S. King scheduled for December 2010. In an order dated Nov. 4, 2009, the MPUC authorized NSP-Minnesota to collect approximately \$3.5 million from customers through a mercury rider in 2010.

On Dec. 21, 2009, NSP-Minnesota filed the plans for mercury control at Sherco Units 1 and 2 with the MPUC and the MPCA. Assuming these plans are approved, NSP-Minnesota expects to file for recovery of the costs to implement these plans through the mercury cost recovery rider.

Regional Haze Rules — In June 2005, the EPA finalized amendments to the July 1999 regional haze rules. These amendments apply to the provisions of the regional haze rule that require emission controls, known as BART, for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze.

NSP-Minnesota submitted its BART alternatives analysis for Sherco Units 1 and 2 in October 2006. The MPCA reviewed the BART analyses for all units in Minnesota and determined that overall, compliance with CAIR is better than BART. On Nov. 13, 2008, NSP-Minnesota submitted a revised BART alternatives analysis letter to the MPCA to account for increased construction and equipment costs. The underlying conclusions and proposed emission control equipment, however, remained unchanged from the original 2006 BART analysis. The MPCA completed their BART determination and proposed SO₂ and NO_x limits in the draft state implementation plan (SIP) that are equivalent to the reductions made under CAIR.

On Oct. 21, 2009, the United States Department of Interior certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to pollution emissions from Xcel Energy's Sherco Plant Units 1 and 2. The EPA currently administers the 1980 Visibility Protection Rules for the State of Minnesota through a Federal Implementation Plan. As such, EPA Region 5 is required to make its own determination as to whether Sherco Units 1 and 2 cause or contribute to visibility impairment and if so, to determine the appropriate BART levels of control.

The MPCA determined that this certification does not alter the proposed SIP. The SIP proposes BART controls for Sherco that are designed to improve visibility in the national parks, but does not require Selective Catalytic Reduction (SCR) on Units 1 and 2. The MPCA concluded that the minor visibility benefits derived from SCR do not outweigh the substantial costs. On Dec. 15, 2009, the MPCA Citizens Board approved the SIP, which has been submitted to the EPA for approval.

Federal Clean Water Act — The federal Clean Water Act requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available (BTA) for minimizing adverse environmental impacts. In July 2004, the EPA published phase II of the rule, which applies to existing cooling water intakes at steam-electric power plants. Several lawsuits were filed against the EPA in the United States Court of Appeals for the Second Circuit (Court of Appeals) challenging the phase II rulemaking. In January 2007, the Court of Appeals issued its decision and remanded the rule to the EPA for reconsideration. In June 2007, the EPA suspended the deadlines and referred any implementation to each state's best professional judgment until the EPA is able to fully respond to the remand. In April 2008, the U. S. Supreme Court granted limited review of the Court of Appeals' opinion to determine whether the EPA has the authority to consider costs and benefits in assessing BTA. On April 1, 2009, the U. S. Supreme Court issued a decision in *Entergy Corp. v. Riverkeeper, Inc.*, concluding that the EPA can consider a cost benefit analysis when establishing BTA. The decision overturned only one aspect of the Court of Appeals' earlier opinion, and gives the EPA the discretion to consider costs and benefits when it reconsiders its phase II rules. Until the EPA fully responds to the Court of Appeals' decision, the rule's compliance requirements and associated deadlines will remain unknown. As such, it is not possible to provide an accurate estimate of the overall cost of this rulemaking at this time.

The MPCA exercised its authority under best professional judgment to require the Black Dog Generating Station in its recently renewed wastewater discharge permit to create a plan by April 2010 to reduce the plant intake's impact on aquatic wildlife. NSP-Minnesota is discussing alternatives with the local community and regulatory agencies to address this concern.

Asset Retirement Obligations

NSP-Minnesota records future plant removal obligations as a liability at fair value with a corresponding increase to the carrying values of the related long-lived assets in accordance with *ASC 410 Asset Retirement and Environmental Obligations*. This liability will be

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increased over time by applying the interest method of accretion to the liability and the capitalized costs will be depreciated over the useful life of the related long-lived assets. The recording of the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset.

Recorded AROs — AROs have been recorded for plant related to nuclear production, steam production, electric transmission and distribution, gas distribution and office buildings. The steam production obligation includes asbestos, ash containment facilities, radiation sources and decommissioning. The asbestos recognition associated with the steam production includes certain plants at NSP-Minnesota. NSP-Minnesota also recorded asbestos recognition for its general office building.

Generally, this asbestos abatement removal obligation originated in 1973 with the Clean Air Act (CAA), which applied to the demolition of buildings or removal of equipment containing asbestos that can become airborne on removal. AROs also have been recorded for NSP-Minnesota steam production related to ash-containment facilities such as bottom ash ponds, evaporation ponds and solid waste landfills. The origination date on the ARO recognition for ash-containment facilities at steam plants was the in-service date of various facilities. Additional AROs have been recorded for NSP-Minnesota steam production plant related to radiation sources in equipment used to monitor the flow of coal, lime and other materials through feeders.

NSP-Minnesota recognized an ARO for the retirement costs of natural gas mains and for the removal of electric transmission and distribution equipment. The electric transmission and distribution ARO consists of many small potential obligations associated with polychlorinated biphenyls (PCBs), mineral oil, storage tanks, treated poles, lithium batteries, mercury and street lighting lamps. These electric and natural gas assets have many in-service dates for which it is difficult to assign the obligation to a particular year. Therefore, the obligation was measured using an average service life.

For the nuclear assets, the ARO associated with the decommissioning of two NSP-Minnesota nuclear generating plants, Monticello and Prairie Island, originates with the in-service date of the facility. Monticello began operation in 1971. Prairie Island units 1 and 2 began operation in 1973 and 1974, respectively. See Note 15 to the financial statements for further discussion of nuclear obligations.

A reconciliation of the beginning and ending aggregate carrying amounts of NSP-Minnesota's AROs is shown in the table below for the 12 months ended Dec. 31, 2009 and Dec. 31, 2008, respectively:

(Thousands of Dollars)	Beginning Balance Jan. 1, 2009	Liabilities Recognized	Liabilities Settled	Accretion	Revisions to Prior Estimates	Ending Balance Dec. 31, 2009
Electric plant						
Steam production asbestos	\$ 19,520	\$ —	\$ —	\$ 1,126	\$ (3,870)	\$ 16,776
Steam production ash containment	13,844	—	—	814	(2,111)	12,547
Steam production radiation sources	61	—	—	4	(8)	57
Nuclear production decommissioning	1,013,342	—	—	61,469	(315,888)	758,923
Wind production	7,447	—	—	483	(179)	7,751
Electric transmission and distribution	151	—	—	9	(20)	140
Natural gas plant						
Gas transmission and distribution	245	—	—	16	—	261
Common and other property						
Common general plant asbestos	1,079	—	—	59	(117)	1,021
Total liability	<u>\$ 1,055,689</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 63,980</u>	<u>\$ (322,193)</u>	<u>\$ 797,476</u>

The fair value of NSP-Minnesota assets legally restricted for purposes of settling the nuclear AROs is \$1.2 billion as of Dec. 31, 2009, including external nuclear decommissioning investment funds and internally funded amounts.

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NSP-Minnesota also incurred revisions for asbestos, nuclear production, radiation sources, wind turbines, ash-containment facilities and electric transmission and distribution asset retirement obligations due to revised estimates and end of life dates.

The revised end of life date for the Prairie Island nuclear plant approved by the MPUC in 2008 and effective Jan. 1, 2009 resulted in the nuclear production decommissioning ARO and related regulatory asset decreasing by \$315.9 million in the fourth quarter of 2009.

(Thousands of Dollars)	Beginning Balance Jan. 1, 2008	Liabilities Recognized	Liabilities Settled	Accretion	Revisions to Prior Estimates	Ending Balance Dec. 31, 2008
Electric plant						
Steam production asbestos	\$ 22,423	\$ —	\$ —	\$ 1,279	\$ (4,182)	\$ 19,520
Steam production ash containment	18,111	—	—	1,001	(5,268)	13,844
Steam production radiation sources	—	61	—	—	—	61
Nuclear production decommissioning	1,209,746	—	—	71,370	(267,774)	1,013,342
Wind production	—	7,408	—	39	—	7,447
Electric transmission and distribution	125	—	—	7	19	151
Natural gas plant						
Gas transmission and distribution	12,685	—	—	314	(12,754)	245
Common and other property						
Common general plant asbestos	1,278	—	—	70	(269)	1,079
Total liability	<u>\$ 1,264,368</u>	<u>\$ 7,469</u>	<u>\$ —</u>	<u>\$ 74,080</u>	<u>\$ (290,228)</u>	<u>\$ 1,055,689</u>

A new decommissioning study filed with the MPUC in 2008 proposed the extension of the final removal date of the Monticello and Prairie Island nuclear plants by 14 and 26 years, respectively, effective Jan. 1, 2009. As a result of the studies for the Monticello and Prairie Island nuclear plants, the nuclear production decommissioning ARO and related regulatory asset decreased by \$128.5 million and \$139.3 million, respectively, in the fourth quarter of 2008.

Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to \$12.5 billion under the Price-Anderson amendment to the Atomic Energy Act of 1954, as amended. NSP-Minnesota has secured \$300 million of coverage for its public liability exposure with a pool of insurance companies. The remaining \$12.2 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to \$117.5 million per reactor per accident for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is \$17.5 million per reactor during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective Oct. 29, 2008. The next adjustment is due on or before Oct. 29, 2013.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are \$2.3 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to

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maximum assessments of approximately \$15.2 million for business interruption insurance and \$30.9 million for property damage insurance if losses exceed accumulated reserve funds.

Legal Contingencies

Lawsuits and claims arise in the normal course of business. Management, after consultation with legal counsel, has recorded an estimate of the probable cost of settlement or other disposition of them. The ultimate outcome of these matters cannot presently be determined. Accordingly, the ultimate resolution of these matters could have a material adverse effect on NSP-Minnesota's financial position and results of operations.

Environmental Litigation

Carbon Dioxide (CO₂) Emissions Lawsuit — In 2004, the attorneys general of eight states and New York City, as well as several environmental groups, filed lawsuits in U. S. District Court in the Southern District of New York against five utilities, including Xcel Energy, the parent company of NSP-Minnesota, to force reductions in CO₂ emissions. The other utilities include American Electric Power Co., Southern Co., Cinergy Corp. and Tennessee Valley Authority. The lawsuits allege that CO₂ emitted by each company is a public nuisance as defined under state and federal common law because it has contributed to global warming. The lawsuits do not demand monetary damages. Instead, the lawsuits ask the court to order each utility to cap and reduce its CO₂ emissions. On Sept. 19, 2005, the court granted a motion to dismiss on constitutional grounds. Plaintiffs filed an appeal to the U. S. Court of Appeals for the Second Circuit. On Sept. 21, 2009, the Court of Appeals issued an opinion reversing the lower court decision. On Nov. 5, 2009 the defendants, including Xcel Energy, filed a petition for rehearing and en banc review. It is uncertain when the Court of Appeals will respond to the petition.

Comer vs. Xcel Energy Inc. et al. — In 2006, Xcel Energy, the parent company of NSP-Minnesota, received notice of a purported class action lawsuit filed in U. S. District Court in the Southern District of Mississippi. The lawsuit names more than 45 oil, chemical and utility companies, including Xcel Energy, as defendants and alleges that defendants' CO₂ emissions "were a proximate and direct cause of the increase in the destructive capacity of Hurricane Katrina." Plaintiffs allege in support of their claim, several legal theories, including negligence and public and private nuisance and seek damages related to the loss resulting from the hurricane. Xcel Energy believes this lawsuit is without merit and intends to vigorously defend itself against these claims. In August 2007, the court dismissed the lawsuit in its entirety against all defendants on constitutional grounds. Plaintiffs filed a notice of appeal to the U. S. Court of Appeals for the Fifth Circuit. On Oct. 16, 2009, the U. S. Court of Appeals for the Fifth Circuit reversed the district court decision, in part, concluding that the plaintiffs pleaded sufficient facts to overcome the constitutional challenges that formed the basis for dismissal by the district court. On Nov. 27, 2009, defendants, including Xcel Energy, filed a petition for en banc review. It is uncertain when the Court of Appeals will respond to the petition.

Native Village of Kivalina vs. Xcel Energy Inc. et al. — In 2008, the City and Native Village of Kivalina, Alaska, filed a lawsuit in U. S. District Court for the Northern District of California against Xcel Energy, the parent company of NSP-Minnesota, and 23 other utilities, oil, gas and coal companies. Plaintiffs claim that defendants' emission of CO₂ and other GHGs contribute to global warming, which is harming their village. Xcel Energy believes the claims asserted in this lawsuit are without merit and joined with other utility defendants in filing a motion to dismiss on June 30, 2008. On Oct. 15, 2009, the U. S. District Court dismissed the lawsuit on constitutional grounds. On Nov. 5, 2009, plaintiffs filed a notice of appeal to the U. S. Court of Appeals for the Ninth Circuit.

Employment, Tort and Commercial Litigation

Nuclear Waste Disposal Litigation — In 1998, NSP-Minnesota filed a complaint in the U. S. Court of Federal Claims against the United States requesting breach of contract damages for the U. S. Department of Energy's (DOE) failure to begin accepting spent nuclear fuel by Jan. 31, 1998, as required by the contract between the DOE and NSP-Minnesota. At trial, NSP-Minnesota claimed damages in excess of \$100 million through Dec. 31, 2004. On Sept. 26, 2007, the court awarded NSP-Minnesota \$116.5 million in damages. In December 2007, the court denied the DOE's motion for reconsideration. In February 2008, the DOE filed an appeal to the U. S. Court of Appeals for the Federal Circuit, and NSP-Minnesota cross-appealed on the cost of capital issue. In April 2008, the DOE asked the Court of Appeals to stay briefing until the appeals in several other nuclear waste cases have been decided, and the Court of Appeals granted the request. In December 2008, NSP-Minnesota made a motion in the Court of Appeals to lift the stay, which was denied by the Court of Appeals in February 2009. Results of the judgment will not be recorded in earnings until the appeal,

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regulatory treatment and amounts to be shared with ratepayers have been resolved. Given the uncertainties, it is unclear as to how much, if any, of this judgment will ultimately have a net impact on earnings.

In August 2007, NSP-Minnesota filed a second complaint against the DOE in the U. S. Court of Federal Claims (NSP II), again claiming breach of contract damages for the DOE's continuing failure to abide by the terms of the contract. This lawsuit will claim damages for the period Jan. 1, 2005 through Dec. 31, 2008, which includes costs associated with the storage of spent nuclear fuel at Prairie Island and Monticello, as well as the costs of complying with state regulation relating to the storage of spent nuclear fuel. Per the court's scheduling order, NSP-Minnesota's expert report on damages was submitted on April 15, 2009, and asserts damages in excess of \$250 million. In November 2009, the Court ordered the DOE to submit its expert report by May 17, 2010. Trial is expected to take place in mid to late 2010.

Siewert vs. Xcel Energy — In 2004, plaintiffs, the owners and operators of a Minnesota dairy farm, brought an action in Minnesota state court against NSP-Minnesota alleging negligence in the handling, supplying, distributing and selling of electrical power systems; negligence in the construction and maintenance of distribution systems; and failure to warn or adequately test such systems. Plaintiffs allege decreased milk production, injury, and damage to a dairy herd as a result of stray voltage resulting from NSP-Minnesota's distribution system. Plaintiffs claim losses of approximately \$7 million. NSP-Minnesota denies all allegations. In December 2008, the Court of Appeals issued a decision ordering dismissal of Plaintiffs' claims for injunctive relief, but otherwise rejecting NSP-Minnesota's contentions and ordering the matter remanded for trial. The Minnesota Supreme Court subsequently granted NSP-Minnesota's petition for further review and heard oral arguments on Dec. 2, 2009. It is uncertain when the Minnesota Supreme Court will render a decision.

14. Nuclear Obligations

Fuel Disposal — NSP-Minnesota is responsible for temporarily storing used or spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from NSP-Minnesota's nuclear plants as well as from other U. S. nuclear plants. NSP-Minnesota has funded its portion of the DOE's permanent disposal program since 1981. The fuel disposal fees are based on a charge of 0.1 cent per Kwh sold to customers from nuclear generation. Fuel expense includes the DOE fuel disposal assessments of approximately \$12 million in 2009, \$13 million in 2008 and \$13 million 2007, respectively. In total, NSP-Minnesota had paid approximately \$398 million to the DOE through Dec. 31, 2009. The Nuclear Waste Policy Act of 1982 required the DOE to begin accepting spent nuclear fuel no later than Jan. 31, 1998. NSP-Minnesota and other utilities have commenced lawsuits against the DOE to recover damages caused by the DOE's failure to meet its statutory and contractual obligations.

NSP-Minnesota has its own temporary on-site storage facilities for spent fuel at its Monticello and Prairie Island nuclear plants, which consist of storage pools and dry cask facilities at both sites. The amount of spent fuel storage capacity currently authorized by the NRC and the MPUC will allow NSP-Minnesota to continue operation of its Prairie Island nuclear plant until the end of its current license terms in 2013 and 2014 and its Monticello nuclear plant until the end of its renewed operating license in 2030. Other alternatives for spent fuel storage are being investigated until a DOE facility is available, including pursuing the establishment of a private facility for interim storage of spent nuclear fuel as part of a consortium of electric utilities.

Regulatory Plant Decommissioning Recovery — Decommissioning of NSP-Minnesota's nuclear facilities is planned for the period from cessation of operations through 2067, assuming the prompt dismantlement method. NSP-Minnesota is currently recording the regulatory costs for decommissioning over the MPUC-approved cost-recovery period and including the accruals in a regulatory liability account. The total decommissioning cost obligation is recorded as an ARO in accordance with *ASC 410 Asset Retirement and Environmental Obligations*.

Monticello began operation in 1971 and with its renewed operating license and CON for spent fuel capacity to support 20 years of extended operation can operate until 2030. The Monticello 20-year depreciation life extension until September 2030 was granted by the MPUC in 2007. Construction of the Monticello dry-cask storage facility is complete and 10 of the 30 canisters authorized have been filled and placed in the facility.

Prairie Island units 1 and 2 began operation in 1973 and 1974, respectively, and are currently licensed to operate until 2013 and 2014, respectively. In April 2008, NSP-Minnesota filed an application with the NRC to renew the operating license of its two nuclear reactors at Prairie Island for an additional 20 years until 2033 and 2034, respectively. The PIIC filed contentions in the NRC's license

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renewal proceeding in August 2008. The PIIC request was referred to an ASLB for review. The ASLB has granted the PIIC hearing request and has admitted seven of the 11 contentions filed. To date, all seven admitted contentions have been resolved and removed from the ASLB docket. Subsequent to the NRC issuance of the final Safety Evaluation Report and the draft supplemental environmental impact statement, the PIIC filed four additional contentions. The ASLB has admitted one of the contentions and has not issued a decision on the other three. NSP-Minnesota is challenging the admitted contention, and a decision on whether the other contentions will be accepted will be made in early 2010. If the contentions are not resolved, the resulting adjudicatory process is expected to add approximately eight months onto the NRC's standard 22 month review schedule, resulting in a decision on the Prairie Island license renewal in late 2010.

The total obligation for decommissioning currently is expected to be funded 100 percent by external funds, as approved by the MPUC, when decommissioning commences. The MPUC last approved NSP-Minnesota's nuclear decommissioning study request in October 2009, using 2008 cost data. The next study update will be submitted in October 2011 for the 2012 accrual. The MPUC approval, eliminated 2009 decommissioning funding for Minnesota retail customers, due to a full extension of the accrual period for the Monticello unit from 2020 to 2030, along with an extension of the accrual period for Prairie Island (from 2013 for Unit 1 and 2014 for Unit 2 to 2023 and 2024 respectively). Further, in November 2009, the MPUC also approved a proposal to refund the Minnesota portion of the Monticello escrow fund in a supplemental filing.

The assets held in trusts, primarily consist of investments in fixed income securities, such as tax-exempt municipal bonds and U. S. government securities that mature in one to 20 years and common stock of public companies. NSP-Minnesota plans to reinvest matured securities until decommissioning begins.

Consistent with cost-recovery in utility customer rates, NSP-Minnesota previously recorded annual decommissioning accruals based on periodic site-specific cost studies and a presumed level of dedicated funding. Cost studies quantify decommissioning costs in current dollars. The most recent study, which resulted in an authorization of no funding presumes that costs will escalate in the future at a rate of 2.89 percent per year. The total estimated decommissioning costs that will ultimately be paid, net of income earned by external trust funds, is currently being accrued using an annuity approach over the approved plant-recovery period. This annuity approach uses an assumed rate of return on funding, which is currently 6.30 percent, net of tax, for external funding. The net unrealized loss on nuclear decommissioning investments is deferred as a regulatory liability based on the assumed offsetting against decommissioning costs in current ratemaking treatment.

The external funds are held in trust and in escrow. The portion in escrow is subject to refund if approved by the various rate commissions. The MPUC authorized the return of \$23.5 million of funds associated with the Monticello plant for the Minnesota retail jurisdictions. This amount was withdrawn in December 2009 and was refunded on customer's bills in February 2010.

At Dec. 31, 2009, NSP-Minnesota had recorded and recovered in rates cumulative decommissioning expense of \$1.3 billion. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation based on approved regulatory recovery parameters. Xcel Energy believes future decommissioning cost expense, if necessary, will continue to be recovered in customer rates. These amounts are not those recorded in the financial statements for the ARO.

(Thousands of Dollars)	2009	2008
Estimated decommissioning cost obligation from most recently approved study (2008 dollars)	\$ 2,308,196	\$ 1,683,750
Effect of escalating costs to 2009 and 2008 dollars (2.89 and 3.61 percent per year, respectively)	66,707	189,012
Estimated decommissioning cost obligation in current dollars	2,374,903	1,872,762
Effect of escalating costs to payment date (2.89 and 3.61 percent per year, respectively)	2,741,460	1,254,064
Estimated future decommissioning costs (undiscounted)	5,116,363	3,126,826
Effect of discounting obligation (using risk-free interest rate)	(3,973,493)	(1,847,526)
Discounted decommissioning cost obligation	1,142,870	1,279,300
Assets held in external decommissioning trust	1,248,739	1,075,294
Discounting decommissioning obligation compared to assets currently held in external trust	\$ (105,869)	\$ 204,006

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Decommissioning expenses recognized include the following components:

(Thousands of Dollars)	2009	2008
Annual decommissioning cost expense reported as depreciation expense:		
Externally funded	\$ 2,849	\$ 43,239
Internally funded (including interest costs)	(884)	(819)
Net decommissioning expense recorded	<u>\$ 1,965</u>	<u>\$ 42,420</u>

Reductions to expense for internally-funded portions in 2009, 2008 and 2007 are a direct result of the 2008 and 2005 decommissioning study jurisdictional allocation and 100 percent external funding approval, effectively unwinding the remaining internal fund over the remaining operating life of the unit. The 2008 nuclear decommissioning filing approved in 2009 has been used for the regulatory presentation. The change in estimated decommissioning obligations was calculated using a cost estimate for Monticello assuming a 60-year operating life.

15. Regulatory Assets and Liabilities

NSP-Minnesota's financial statements are prepared in accordance with the provisions of *ASC 980 Regulated Operations*, as discussed in Note 1 to the financial statements. Under this guidance, regulatory assets and liabilities can be created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. Any portion of the business that is not rate regulated cannot establish regulatory assets and liabilities. If changes in the utility industry or the business of NSP-Minnesota no longer allow for the application of regulatory accounting guidance under GAAP, NSP-Minnesota would be required to recognize the write-off of regulatory assets and liabilities in its statement of income.

The components of unamortized regulatory assets and liabilities on the balance sheets of NSP-Minnesota are:

(Thousands of Dollars)	2009	2008
Regulatory Assets:		
Asset retirement recovery	\$ 1,398,315	\$ 1,367,548
Pension and employee benefit obligations	188,139	153,891
AFDC recorded in plant	133,602	124,242
Contract valuation adjustments	89,026	86,937
Nuclear outage costs	60,747	40,690
Unrealized gains on nuclear decommissioning trust investments	46,551	150,592
Conservation programs	46,028	23,911
Renewable resource costs	27,714	44,790
Deferred electric commodity costs	22,915	11,201
Mankato Energy Center lease normalization	20,014	13,228
Mercury emissions reduction costs	13,733	13,266
Private fuel storage	8,301	9,652
MISO Schedule 16 and 17	9,830	8,742
State commission accounting adjustments	4,631	4,398
Costs to relocate facilities underground	2,845	4,647
Environmental costs	334	611
IRS and state interest deferrals	425	567
Other	652	—
Total regulatory assets	<u>\$ 2,073,802</u>	<u>\$ 2,058,913</u>

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Regulatory Liabilities:

Pre-ARO decommissioning expense	\$ 1,289,094	\$ 1,261,351
Deferred income tax adjustments	32,792	30,787
Investment tax credit deferrals	25,659	27,797
Contract valuation adjustments	20,871	23,355
Nuclear outage costs collected in advance from customers	10,322	13,678
Discounts provided to customers	2,634	3,943
Gain on sales of emission allowances	2,239	2,727
Interest on income tax refunds	1,302	1,736
Gas pipeline refunds	(7)	(7)
Total regulatory liabilities	<u>\$ 1,384,906</u>	<u>\$ 1,365,367</u>

16. Related Party Transactions

Xcel Energy Services Inc. provides management, administrative and other services for the subsidiaries of Xcel Energy, including NSP-Minnesota. The services are provided and billed to each subsidiary in accordance with Service Agreements executed by each subsidiary. Costs are charged directly to the subsidiary which uses the service whenever possible and are allocated if they cannot be directly assigned.

Xcel Energy has established a utility money pool arrangement with the utility subsidiaries. See Note 4 for further discussion of this borrowing arrangement.

The electric production and transmission costs of the entire NSP system are shared by NSP-Minnesota and NSP-Wisconsin. The Interchange Agreement provides for the sharing of all costs of generation and transmission facilities of the system, including capital costs.

The table below contains significant affiliate transactions among the companies and related parties including billings under the Interchange Agreement for the years ended Dec. 31:

(Thousands of Dollars)	2009	2008
Operating revenues:		
Electric	\$ 389,023	\$ 390,143
Gas	309	312
Operating expenses:		
Purchased power	64,059	64,195
Transmission expense	45,192	42,167
Other operations — paid to Xcel Energy Services Inc.	303,345	274,549
Interest expense	573	1,503
Interest income	30	2,583

Accounts receivable and payable with affiliates at Dec. 31, was:

(Thousands of Dollars)	2009		2008	
	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Wisconsin	\$ 31,243	\$ —	\$ 12,416	\$ —
PSCo	—	15,789	—	15,987
SPS	—	2,268	—	3,330
Other subsidiaries of Xcel Energy	65	65,702	2	33,062
	<u>\$ 31,308</u>	<u>\$ 83,759</u>	<u>\$ 12,418</u>	<u>\$ 52,379</u>

NSP-Wisconsin obtains short-term borrowings from NSP-Minnesota at NSP-Minnesota's average daily interest rate, including the cost of NSP-Minnesota's compensating balance requirements. At Dec. 31, 2009 and 2008, NSP-Minnesota had notes receivable

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outstanding from NSP-Wisconsin in the amount of \$15.5 million and \$0.0 million, respectively.

17. Supplementary Cash Flow Data

(Thousands of dollars)

Supplemental disclosure of cash flow information:

	<u>2009</u>		<u>2008</u>
Cash paid for interest (net of amounts capitalized)	\$ (177,973)	\$	(168,506)
Cash received (paid) for income taxes, net	23,936		(44,062)
Supplemental disclosure of non-cash flow investing transactions:			
Property, plant and equipment additions	\$ 34,172	\$	24,109

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(2,435,829)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				(411,960)
4	Total (lines 2 and 3)				(411,960)
5	Balance of Account 219 at End of Preceding Quarter/Year				(2,847,789)
6	Balance of Account 219 at Beginning of Current Year				(2,847,789)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value	411,455			207,597
9	Total (lines 7 and 8)	411,455			207,597
10	Balance of Account 219 at End of Current Quarter/Year	411,455			(2,640,192)

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	8,607,940	96,221	6,268,332		
2	(188,307)		(188,307)		
3	(1,444,252)	(4,019,073)	(5,875,285)		
4	(1,632,559)	(4,019,073)	(6,063,592)	285,141,015	279,077,423
5	6,975,381	(3,922,852)	204,740		
6	6,975,381	(3,922,852)	204,740		
7	(118,828)	2,226,258	2,107,430		
8	(1,898,941)	679,985	(599,904)		
9	(2,017,769)	2,906,243	1,507,526	293,770,340	295,277,866
10	4,957,612	(1,016,609)	1,712,266		

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	9,684,496,908	8,405,972,466
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	1,496,590,654	1,361,906,197
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	11,181,087,562	9,767,878,663
9	Leased to Others	2,729,868	2,729,868
10	Held for Future Use	3,791,367	3,791,367
11	Construction Work in Progress	588,011,455	558,633,311
12	Acquisition Adjustments	222,385	222,385
13	Total Utility Plant (8 thru 12)	11,775,842,637	10,333,255,594
14	Accum Prov for Depr, Amort, & Depl	5,397,551,717	4,691,233,229
15	Net Utility Plant (13 less 14)	6,378,290,920	5,642,022,365
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	5,161,348,221	4,660,457,675
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	234,199,033	28,771,091
22	Total In Service (18 thru 21)	5,395,547,254	4,689,228,766
23	Leased to Others		
24	Depreciation	1,782,078	1,782,078
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)	1,782,078	1,782,078
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	222,385	222,385
33	Total Accum Prov (equals 14) (22,26,30,31,32)	5,397,551,717	4,691,233,229

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
857,781,079				420,743,363	3
					4
					5
90,927,294				43,757,163	6
					7
948,708,373				464,500,526	8
					9
					10
6,842,472				22,535,672	11
					12
955,550,845				487,036,198	13
420,797,520				285,520,968	14
534,753,325				201,515,230	15
					16
					17
419,439,868				81,450,678	18
					19
					20
1,357,652				204,070,290	21
420,797,520				285,520,968	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
420,797,520				285,520,968	33

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	7,939,390	25,622,550
3	Nuclear Materials	116,277,906	92,759,674
4	Allowance for Funds Used during Construction	7,046,001	7,823,096
5	(Other Overhead Construction Costs, provide details in footnote)	63,812	70,429
6	SUBTOTAL (Total 2 thru 5)	131,327,109	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		68,985,912
9	In Reactor (120.3)	307,037,358	148,618,043
10	SUBTOTAL (Total 8 & 9)	307,037,358	
11	Spent Nuclear Fuel (120.4)	1,172,828,794	56,284,531
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	1,355,572,641	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	255,620,620	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance End of Year (f)	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)		
			1
	23,061,289	10,500,651	2
	118,568,358	90,469,222	3
	6,987,230	7,881,867	4
	71,255	62,986	5
		108,914,726	6
			7
	68,915,823	70,089	8
	56,284,531	399,370,870	9
		399,440,959	10
		1,229,113,325	11
			12
-80,104,390		1,435,677,031	13
		301,791,979	14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
FOOTNOTE DATA			

Schedule Page: 202 Line No.: 2 Column: e

Classified to Account 120.2 and 120.3.

Schedule Page: 202 Line No.: 3 Column: e

Classified to Account 120.2 and 120.3.

Schedule Page: 202 Line No.: 4 Column: e

Classified to Account 120.2 and 120.3.

Schedule Page: 202 Line No.: 5 Column: e

Classified to Account 120.2 and 120.3.

Schedule Page: 202 Line No.: 5 Column: f

Consists of Administration and General costs.

Schedule Page: 202 Line No.: 8 Column: e

Transferred to Account 120.3.

Schedule Page: 202 Line No.: 9 Column: e

Transferred to Account 120.4.

Schedule Page: 202 Line No.: 15 Column: b

Not estimated because of disposal contracts with the Department of Energy resulting from the Nuclear Waste Disposal Act of 1982.

Schedule Page: 202 Line No.: 16 Column: b

Not estimated because of disposal contracts with the Department of Energy resulting from the Nuclear Waste Disposal Act of 1982.

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

- Report below the original cost of electric plant in service according to the prescribed accounts.
- 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.
- Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
- 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.
- Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
- 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	35,115,520	-497
4	(303) Miscellaneous Intangible Plant	29,491,090	2,178,505
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	64,606,610	2,178,008
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	9,348,830	
9	(311) Structures and Improvements	312,494,757	5,551,210
10	(312) Boiler Plant Equipment	1,313,473,593	16,160,743
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	308,875,600	5,780,002
13	(315) Accessory Electric Equipment	175,168,322	3,163,882
14	(316) Misc. Power Plant Equipment	50,648,942	2,086,242
15	(317) Asset Retirement Costs for Steam Production	-4,044,214	-5,988,544
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,165,965,830	26,753,535
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	1,170,466	
19	(321) Structures and Improvements	366,963,462	3,077,962
20	(322) Reactor Plant Equipment	859,949,961	29,914,946
21	(323) Turbogenerator Units	225,747,402	56,665,901
22	(324) Accessory Electric Equipment	236,025,377	1,951,802
23	(325) Misc. Power Plant Equipment	121,076,214	4,885,569
24	(326) Asset Retirement Costs for Nuclear Production	-128,748,875	-315,887,554
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	1,682,184,007	-219,391,374
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	1,698,851	
28	(331) Structures and Improvements	544,221	
29	(332) Reservoirs, Dams, and Waterways	6,731,348	125,140
30	(333) Water Wheels, Turbines, and Generators	1,105,306	1,244,219
31	(334) Accessory Electric Equipment	349,415	29,486
32	(335) Misc. Power PLant Equipment	60,825	
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)	10,489,966	1,398,845
36	D. Other Production Plant		
37	(340) Land and Land Rights	23,601,631	16,208
38	(341) Structures and Improvements	43,913,462	80,405,927
39	(342) Fuel Holders, Products, and Accessories	13,261,562	63,703,906
40	(343) Prime Movers		
41	(344) Generators	853,884,465	43,230,428
42	(345) Accessory Electric Equipment	47,834,703	78,313,082
43	(346) Misc. Power Plant Equipment	4,692,766	11,880,962
44	(347) Asset Retirement Costs for Other Production	7,407,529	-179,415
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	994,596,118	277,371,098
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,853,235,921	86,132,104

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	57,785,590	-5,776,791
49	(352) Structures and Improvements	34,137,424	1,706,258
50	(353) Station Equipment	666,074,121	61,931,357
51	(354) Towers and Fixtures	109,539,952	-1
52	(355) Poles and Fixtures	456,336,737	52,507,644
53	(356) Overhead Conductors and Devices	246,863,482	14,143,807
54	(357) Underground Conduit	8,378,602	
55	(358) Underground Conductors and Devices	14,526,016	16
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)	1,593,641,924	124,512,290
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	13,595,012	-1,845
61	(361) Structures and Improvements	28,314,884	796,108
62	(362) Station Equipment	421,818,478	17,044,310
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	275,127,342	10,265,982
65	(365) Overhead Conductors and Devices	322,152,894	14,530,009
66	(366) Underground Conduit	180,420,819	5,527,417
67	(367) Underground Conductors and Devices	817,297,817	34,952,186
68	(368) Line Transformers	344,563,511	17,201,114
69	(369) Services	256,916,298	4,965,172
70	(370) Meters	101,421,115	8,098,417
71	(371) Installations on Customer Premises	22,705,193	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	46,845,326	2,308,630
74	(374) Asset Retirement Costs for Distribution Plant	94,784	-19,864
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,831,273,473	115,667,636
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	4,356,206	91,782
87	(390) Structures and Improvements	55,496,590	1,276,897
88	(391) Office Furniture and Equipment	34,375,527	4,732,300
89	(392) Transportation Equipment	36,342,769	6,177,358
90	(393) Stores Equipment	2,249,636	
91	(394) Tools, Shop and Garage Equipment	36,908,989	5,157,297
92	(395) Laboratory Equipment	4,508,851	467,536
93	(396) Power Operated Equipment	3,644,573	3,961,710
94	(397) Communication Equipment	16,895,690	6,239,929
95	(398) Miscellaneous Equipment	2,803,488	15,927
96	SUBTOTAL (Enter Total of lines 86 thru 95)	197,582,319	28,120,736
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)	197,582,319	28,120,736
100	TOTAL (Accounts 101 and 106)	9,540,340,247	356,610,774
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)	9,540,340,247	356,610,774

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
			35,115,023	3
			31,669,595	4
			66,784,618	5
				6
				7
		-450,132	8,898,698	8
2,484,760		-26,284,587	289,276,620	9
52,859,910		-25,107,180	1,251,667,246	10
				11
31,914,964		-567,997	282,172,641	12
1,824,377		-16,018,889	160,488,938	13
500,988		-5,289,056	46,945,140	14
			-10,032,758	15
89,584,999		-73,717,841	2,029,416,525	16
				17
			1,170,466	18
174,976			369,866,448	19
1,610,405		-869,020	887,385,482	20
112,268			282,301,035	21
313,426		1,028,142	238,691,895	22
		-159,122	125,802,661	23
			-444,636,429	24
2,211,075			1,460,581,558	25
				26
			1,698,851	27
			544,221	28
			6,856,488	29
			2,349,525	30
			378,901	31
			60,825	32
				33
				34
			11,888,811	35
				36
46,701		-8,236,685	15,334,453	37
19,627		25,997,685	150,297,447	38
94,267			76,871,201	39
				40
3,989,521		32,010,667	925,136,039	41
421,116		18,949,542	144,676,211	42
193,906		4,996,632	21,376,454	43
			7,228,114	44
4,765,138		73,717,841	1,340,919,919	45
96,561,212			4,842,806,813	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
		-283,464	51,725,335	48
27,067		2,857,972	38,674,587	49
4,135,009		-112,717	723,757,752	50
25,954		-33	109,513,964	51
1,288,931		-25,004,488	482,550,962	52
2,045,552		24,323,193	283,284,930	53
14,529			8,364,073	54
393,655		-18,353	14,114,024	55
				56
				57
7,930,697		1,762,110	1,711,985,627	58
				59
		6,737	13,599,904	60
407,177		2,594,658	31,298,473	61
2,042,577		-590,125	436,230,086	62
				63
-193,937		-2,617,109	282,970,152	64
4,581,574		262,107	332,363,436	65
116,985		-2,249,056	183,582,195	66
3,401,648		-1,070,775	847,777,580	67
5,899,348		-349,960	355,515,317	68
131,112		-170,996	261,579,362	69
			109,519,532	70
			22,705,193	71
				72
1,015,502		3,368,484	51,506,938	73
			74,920	74
17,401,986		-816,035	2,928,723,088	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
2,286			4,445,702	86
			56,773,487	87
141,405		-150,949	38,815,473	88
347,740		237,092	42,409,479	89
			2,249,636	90
5,215,158		-58,064	36,793,064	91
372,410			4,603,977	92
		-179,028	7,427,255	93
2,042,168		261,903	21,355,354	94
58,129		-56,196	2,705,090	95
8,179,296		54,758	217,578,517	96
				97
				98
8,179,296		54,758	217,578,517	99
130,073,191		1,000,833	9,767,878,663	100
				101
				102
				103
130,073,191		1,000,833	9,767,878,663	104

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
FOOTNOTE DATA			

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

Schedule Page: 205 and 207
Line No.: 5, 46, 58, 75, 99
Column: g

Electric Plant in Service (Accounts 101, 102, 103 and 106). The Form 1 reports total intangible plant (line 5), production plant (line 46), transmission plant (line 58), distribution plant (line 75) and general plant (line 99) at the beginning of the year and at the end of the year. The Company uses a 13-month average calculation for the plant in service balances included in the formula. Production plant and distribution plant balances are included in the development of the gross plant and net plant allocators that are used to allocate cost to the transmission function in the formula.

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	ST REGIS CORPORATION	115-13.8 KV SUBSTATION AND			2,729,868
2		115 KV TRANSMISSION LINE #5509			
3		AND A PORTION OF A			
4		TRANSMISSION SUBSTATION			
5					
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44					
45					
46					
47	TOTAL				2,729,868

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				
3	Sioux Falls (So West) Substation	1994	2010+	77,018
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23	Fargo - UG Conduit and Duct Banks	Various	2010+	119,652
24	Fargo - Dist Underground Conductor	Various	2010+	47,068
25	Sioux Falls - Dist Underground Conductor	1975	2010+	6,319
26	Nobles County Sub-Tran-MN	2008	2010+	3,131,770
27	Elec Dist-Mass-MN-Mankato	2009	2010+	409,540
28				
29				
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44				
45				
46	**Footnote from page 106b**			
47	Total			3,791,367

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original	(Mo, Da, Yr)	
	(2) <input type="checkbox"/> A Resubmission	/ /	2009/Q4
FOOTNOTE DATA			

Schedule Page: 214 Line No.: 46 Column: d

Electric Plant Held for Futures Use (Account 105). The Form 1 reports the plant held for future use balances at the end of the year. NSP-Minnesota can only include the transmission-related land and land rights in the formula. NSP-Minnesota uses a 13-month average calculation for the transmission-related land and land rights balances included in the formula.

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Monticello Nuclear Generating Plant Extended Power Uprate	156,979,758
2	Nobles Wind	54,694,074
3	Prairie Island-License Renewal Project	38,533,504
4	Prairie Island-Extended Power Uprate	20,155,890
5	Prairie Island-U2 Steam Generator Replacement	17,785,059
6	Prairie Island-Five TN-40 Casks	13,866,175
7	CapX2020 Brookings Project Development, Non Shared	11,926,628
8	Merricourt Wind	11,478,459
9	Chisago - Lacrosse 115kv Line	10,785,940
10	Minnesota Substation Construction	9,946,169
11	Prairie Island-Replace Instrument Air Compressors	9,699,632
12	Monticello Nuclear Generating Plant Instrument Air System Upgrade	8,932,360
13	Prairie Island-Measurement Uncertainty	8,065,431
14	Prairie Island-Calculation Recovery & Improvement	7,733,007
15	Prairie Island-NFPA 805 Fire Model	7,154,010
16	0953 Lake Junction to Split Rock Minnesota Land Rights	6,738,104
17	CapX2020 LaCrosse Project Development, Non Shared	6,401,791
18	Prairie Island-Piping System Replacement	5,160,922
19	500kV Line Rebuild	5,083,172
20	Monticello Nuclear Generating Plant Security Improvements	5,034,223
21	Sherco Unit 2 Boiler Arch Replacement	4,803,144
22	Monticello Nuclear Generating Plant NFPA 805 Fire Model Tool	4,753,049
23	Sherco Multi-Pollutant	4,575,068
24	South Bend Substation	4,446,840
25	Prairie Island-TN-40 Transport License	4,352,413
26	CapX2020 Fargo Development, Non Shared	4,203,861
27	Mary Lake Line	4,152,341
28	Sherco Unit 3 Turbine Increase Capacity	4,084,214
29	500 kV Line	3,849,310
30	Allen S. King- Reclamation Site	3,770,680
31	Prairie Island-TN-40H Design and Licensing	3,603,936
32	Relocate for Light Rail Transit in St. Paul	3,182,277
33	Replace Transformer Cooling	2,762,738
34	Monticello Nuclear Generating Plant Paperless Recorders	2,671,468
35	Monticello Nuclear Generating Plant Cooling Tower Cell Refurbishment	2,498,013
36	Prairie Island-1R-11/12&2R-11/12 Radiation Monitors	2,363,879
37	Fleet New Unit Electric Transmission, Minnesota	2,333,307
38	CapX2020 Bemidji Project Development, Non Shared	2,203,008
39	Replace Burnside #1 to 28 MVA	2,195,493
40	Fleet New Unit Purchase Electric Operations	1,989,355
41	Sherco Unit 3 Uprate Project	1,988,299
42	West New Ulm Substation	1,967,116
43	TOTAL	558,633,311

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

- Report below descriptions and balances at end of year of projects in process of construction (107)
- 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)
- Minor projects (5% of the Balance End of the Year for Account 107 or \$1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Riverside -Construct New Control Room	1,942,295
2	Monticello Nuclear Generating Plant Turbine Cable	1,802,651
3	Hungry Hollow-Ballard	1,788,022
4	Sherco Unit 1 Boiler Arch Padwelde	1,549,950
5	Prairie Island Chemistry Instrument Upgrade	1,386,607
6	TIP-L Northern States Power Minnesota Wood Structures	1,379,270
7	Minnesota - Distribution Sub Equipment Replacement	1,376,520
8	Wil-South Bend-ESW New 115kV Line	1,347,310
9	Sherco Unit 1 Unit 2 Pond 3S	1,269,475
10	Prairie Island-GL0801 Modeling Software	1,230,956
11	Install Lawrence Creek 28 MVA	1,196,854
12	G287 EnXco Nobles - Network	1,193,268
13	Northern States Power Transmission Line Tool Blanket	1,189,778
14	Allen S. King1C-Lime Slurry Sludge Dewat	1,115,218
15	Ft. Ridgely - West New Ulm Substation	1,114,199
16	Black Dog 316b Improvements	1,091,525
17	Minneapolis-New Underground Extension	-1,086,059
18		
19	Minor Projects	48,841,355
20		
21	Minor Projects	
22		
23		
24		
25		
26		
27		
28		
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32		
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41		
42	**Footnote from page 106b**	
43	TOTAL	558,633,311

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 216.1 Line No.: 17 Column: b

Projects with negative balances are generally attributable to customer payments received in advance of construction or timing differences on the distribution of overheads.

Schedule Page: 216.1 Line No.: 42 Column: b

Construction Work in Progress (Account 107). The Form 1 reports the total Company construction work in progress (CWIP) balances at the end of the year. The Company uses a 13-month average calculation for the specific CWIP project balances included in the formula. The Company can only include CWIP in the formula related to the following specific projects, the balances of which could be a component of the amounts reported on page 216: 1) the Buffalo Ridge Incremental Generation Outlet Project (BRIGO); 2) the 115/161 KV transmission line upgrade (from 69 KV) between Chisago County Minnesota and the Apple River substation in Wisconsin (Chisago-Apple); and 3) four projects in Group 1 of the CapX2020 Project - Twin Cities-Brookings County, Twin Cities-Fargo, Twin Cities-LaCrosse, and Bermidji-Grand Rapids.

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	4,570,036,318	4,568,318,767		1,717,551
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	279,318,958	279,318,958		
4	(403.1) Depreciation Expense for Asset Retirement Costs	-40,821,319	-40,821,319		
5	(413) Exp. of Elec. Plt. Leas. to Others	76,557			76,557
6	Transportation Expenses-Clearing	3,556,579	3,556,579		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	242,130,775	242,054,218		76,557
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	130,033,379	130,024,204		9,175
13	Cost of Removal	16,451,069	16,448,214		2,855
14	Salvage (Credit)	8,671,385	8,671,385		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	137,813,063	137,801,033		12,030
16	Other Debit or Cr. Items (Describe, details in footnote):	-12,114,277	-12,114,277		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,662,239,753	4,660,457,675		1,782,078

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

20	Steam Production	1,093,052,528	1,093,052,528		
21	Nuclear Production	1,456,533,650	1,456,533,650		
22	Hydraulic Production-Conventional	7,351,061	7,351,061		
23	Hydraulic Production-Pumped Storage				
24	Other Production	276,528,229	276,528,229		
25	Transmission	567,039,152	566,626,267		412,885
26	Distribution	1,180,653,906	1,179,284,713		1,369,193
27	Regional Transmission and Market Operation				
28	General	81,081,227	81,081,227		
29	TOTAL (Enter Total of lines 20 thru 28)	4,662,239,753	4,660,457,675		1,782,078

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

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

Net Transfers	6,541,632
Gain/Loss	-
ARO	-
RWIP (2008)	29,335,488
RWIP (2009)	<u>47,991,397</u>
Net change in RWIP	(18,655,909)

Total for Line #16 (12,114,277)

Schedule Page: 219 Line No.: 20 Column: c

Schedule Page: 219
Line No.: 20-26, 28
Column: c

Accumulated Provision for Depreciation (Account 108). The Form 1 reports the accumulated provision for depreciation balances at the end of year. The Company uses a 13-month average calculation for the accumulated provision for depreciation balances included in the formula. Production and distribution accumulated provision for depreciation balances are included in developing the net plant allocator used to allocate costs to the transmission function in the formula.

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

	"Non-Legal" ARO Balances
	<hr/>
Steam Production	32,273,398
Nuclear Production	(20,937,566)
Hydraulic Production - Conventional	818,822
Hydraulic Production - Pumped Storage	-
Other Production	6,431,436
Transmission	73,035,225
Distribution	209,537,951
General	(83,868)
	<hr/>
Total Electric	301,075,398

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	UNITED POWER & LAND CO.			
2	Common Stock-par \$100 per share			4,020,000
3	Undistributed earnings (loss) since acquisition			-2,692,400
4	SUBTOTAL			1,327,600
5				
6	NSP NUCLEAR CO.			
7	Contributed Capital			972,613
8	Undistributed earnings (loss) since acquisition			-549,819
9	SUBTOTAL			422,794
10				
11				
12				
13				
14				
15				
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36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 \$	8,997,093	TOTAL	1,750,394

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		4,020,000		2
-139,248		-2,831,648		3
-139,248		1,188,352		4
				5
				6
		972,613		7
1,102,774		552,955		8
1,102,774		1,525,568		9
				10
				11
				12
				13
				14
				15
				16
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963,526		2,713,920		42

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)	145,713,731	103,697,089	Electric
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)	6,590,441	7,275,101	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	79,242,428	85,253,568	Electric
8	Transmission Plant (Estimated)	2,358,543	2,981,574	Electric
9	Distribution Plant (Estimated)	12,291,260	13,274,144	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	-3,010,734	-3,795,040	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	97,471,938	104,989,347	
13	Merchandise (Account 155)	459,272	454,361	
14	Other Materials and Supplies (Account 156)	13,389	64,565	
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	1		
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	243,658,331	209,205,362	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

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

Materials and Supplies (Accounts 154 and 163). The Form 1 reports the materials and supplies balances at the beginning of the year and at the end of year. The Company uses the average of the beginning of the year and the end of the year materials and supplies balance in the formula.

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

Includes a credit of \$3,037,633 for inventory allocated to Southern Minnesota Municipal Power Agency (41 percent owners of Sherco 3) and a debit of \$26,899 for miscellaneous inventory items such as obsolescence, suspense items, purchase price variance and inventory held for sale.

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

Includes a credit of \$3,142,885 for inventory allocated to Southern Minnesota Municipal Power Agency (41 percent owners of Sherco 3) and a credit of \$652,155 for miscellaneous inventory items such as obsolescence, suspense items, purchase price variance and inventory held for sale.

Schedule Page: 227 Line No.: 16 Column: c

Materials and Supplies (Accounts 154 and 163). The Form 1 reports the materials and supplies balances at the beginning of the year and at the end of year. The Company uses the average of the beginning of the year and the end of the year materials and supplies balance in the formula.

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		2010	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	299,305.00		63,941.00	
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				
19	Other:				
20	Allowances Surrendered	24,778.00			
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	274,527.00		63,941.00	
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	927.00		925.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	927.00			
40	Balance-End of Year			925.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	927.00	64,616		
45	Gains		64,616		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2011		2012		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
63,941.00		63,941.00		1,646,379.00		2,137,507.00		1
								2
								3
				63,941.00		63,941.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
						24,778.00		20
								21
								22
								23
								24
								25
								26
								27
63,941.00		63,941.00		1,710,320.00		2,176,670.00		28
								29
								30
								31
								32
								33
								34
								35
925.00		925.00		45,325.00		49,027.00		36
				1,850.00		1,850.00		37
								38
				925.00		1,852.00		39
925.00		925.00		46,250.00		49,025.00		40
								41
								42
								43
				925.00	6,151	1,852.00	70,767	44
					6,151		70,767	45
								46

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 228 Line No.: 45 Column: m

Gains on sale of Emissions Allowances:

Reconcile gains reported on p 114-7, 229, and 278

	p 114-7 Income Account Acct No. 411.8	p 278 Regulatory Liabilities Acct No. 254	p 229 Gain on Sale
Dec. 31, 2008		<u>(2,727,208)</u>	
Amortize past years' gains to income	(548,918)	548,918	
System gains during 2009		(77,953)	(77,953)
less portion due NSP-Wisconsin based on energy used		11,615	
less portion due SMMPA		5,887	5,887
less gains from allowances relating to a plant owned by NSP-Wisconsin			1,299
subtotal 2009 gains	<u>(548,918)</u>	<u>488,467</u>	<u>(70,767)</u>
Dec. 31, 2009		<u>(2,238,741)</u>	

page 114 and 278 gains are shared between NSP-Minnesota and NSP-Wisconsin based on the portion of energy that each use from the total NSP System. Page 229 are only the gains relating to plants owned by NSP-Minnesota

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		2010	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2011		2012		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
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								44
								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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	none					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	none					
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	F070 Eden Prairie Substation	3,607	143	60,399	143
3	Lake City Substation			27,741	143
4	A345 Eden Prairie Substation	48,391	143	55,399	143
5	F069 Facilities Study				
6	F075 Maple River Substation	4,152	143	21,333	143
7	F077 West Faribault Facility	140,291	143	138,011	143
8	H102 Maple River Substation	81,379	143		
9	F078 Facilities Elm Creek	41,411	143		
10	H103 Mallard Substation	6,021	143		
11	A000 King Substation	3,888	143		
12	A000 Forbes Substation	8,792	143		
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22	Marathon Oil			32,138	143
23	G626 Morgan Sleepy Junction			55,885	143
24	G514 Pleasant Valley	15,486	143	238,138	143
25	G489 Lake Yankton				
26	G549 Sedan to Williams Tap	4,046	143		
27	G587 Cornish to Gibbons	2,224	143	41,433	143
28	G602 Nobles			12,463	143
29	GR5SC Facilities Study Blue Lake	1,109	143	1,451	143
30	GR5SC Franklin			1,835	143
31	Gr5Sc Lake Johanna, Brutte	19,245	143		
32	GR5SC Wilmarth	2,259	143	191,413	143
33	GR5SC Adams				
34	G584 Chanarambie			764	143
35	G620 Kenyon and Dodge Center			22,244	143
36	G621 Chanarambie	49,296	143	7,384	143
37	G364 Brookings			10,612	143
38	G362 Prairie Island Byron			27,207	143
39	G514 Facilities	3,038	143	19,314	143
40	G614 Facilities Jackson Sub			3,577	143

Transmission Service and Generation Interconnection Study Costs (continued)

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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22	G614 Jackson Substation			172,112	143
23	G576 Facilities Study Rock County	28,770	143		
24	G608 Willian Tap and Lake Johanna			4,235	143
25	MISO Facilities Study	1,338	143	3,288	143
26	MISO Group 5 Capbanks	54,488	143	54,488	143
27	G555/G618 MISO Constraint Proj	22,770	143		
28	MISO Short Circuit Analysis	3,577	143		
29	GR5SC Fac Study Hazel Crk 8025	20,190	143		
30	G164 Wind Interconnect Lakefield	1,327	143		
31	G904 Wind Interconnect Rudby	2,284	143		
32					
33					
34					
35					
36					
37					
38					
39					
40	Total	569,379		1,202,864	

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Conservation and Energy Management Program Costs	23,293,310	81,515,436	908	59,244,190	45,564,556
2	- Generally amortized over 12 month					
3	period following the expenditure					
4	- MN Docket E-002/M-09-345					
5	- MN Docket G-002/M-08-391					
6						
7	Gas Site Remediation	611,072		Various	276,601	334,471
8	- Amortization period varies by site					
9	- MN Docket E-002/GR-08-1065					
10						
11	Net of Tax AFUDC in Plant Adjustments	124,242,268	9,359,249			133,601,517
12	- Generally amortized over related plant lives					
13						
14	IRS and State Interest Deferrals	567,210		419	141,803	425,407
15	- Amortized over 4 years					
16	- MN Docket E-002/GR-08-1065					
17						
18	South Dakota Ratemaking Differences	4,398,250	546,000	419.1	313,000	4,631,250
19	- SD Docket F-3422					
20						
21	Renewable Development Fund Rider	34,635,933	16,052,193	Various	24,636,354	26,051,772
22	- MN Docket E-002/M-08-1167					
23						
24	Asset Retirement Recovery	1,367,548,318	30,766,834			1,398,315,152
25						
26	Minnesota State Energy Policy Rider		2,548,603	Various	2,548,603	
27	- MN Docket E-002/M-09-201					
28						
29	Minnesota Transmission Cost Recovery Rider	6,494,558	2,466,662	Various	7,298,861	1,662,359
30	- MN Docket E-002/M-08-1284					
31						
32	Power Contract Valuation Adjustment	86,936,589	2,089,271			89,025,860
33						
34	Costs to Relocate Facilities Underground	4,646,795	506,122	142	2,307,819	2,845,098
35	- MN Docket E-002/M-99-799					
36						
37	Electric Time of Use Study	617,311		908	154,328	462,983
38	- Amortized over 4 years					
39	- MN Docket E-002/GR-08-1065					
40						
41	Mercury Emission Reductions Rider	9,431,832		Various	2,972,550	6,459,282
42	- Amortized over 4 years					
43	- MN Docket E-002/M-08-1065					
44	TOTAL	2,058,913,137	279,425,105		264,535,867	2,073,802,375

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	MISO Schedules 16 and 17	13,105,990		557	3,276,497	9,829,493
2	- Amortized over 4 years					
3	- MN Docket E-002/GR-08-1065					
4						
5	Private Fuel Storage	9,651,743	1,010,000	407.4	2,360,912	8,300,831
6	- Amortized over 4-6 years					
7	- MN Docket E-002/GR-08-1065					
8	- ND Docket PU-07-776					
9	- SD Docket EL09-009					
10						
11	Deferred Electric Commodity Costs	11,200,611	11,714,805			22,915,416
12						
13	Mankato/Cannon Falls Lease Normalization	13,228,422	6,785,550			20,013,972
14						
15	Regulatory Reserve	(4,363,870)	4,363,870			
16						
17	Metro Emissions Reduction Project Rider	3,834,371	3,438,829			7,273,200
18	- MN Docket E-002/M-02-633					
19						
20	Renewable Energy Standard Rider	3,659,549	4,771,016	407.3	8,430,565	
21	- MN Docket E-002/M-08-1033					
22						
23	Deferred Nuclear Outage Costs	40,689,648	66,590,795	Various	46,533,324	60,747,119
24	- Generally amortized over 18-24 months					
25	- MN Docket E-002/M-07-1489					
26	- ND Docket PU-07-774					
27	- SD Docket EL07-035					
28						
29	Benefit Cost Recovery Deficit	153,891,513	34,247,827			188,139,340
30						
31	Unrealized Gains on Decommissioning Trust	150,591,714		Various	104,040,460	46,551,254
32	Investments					
33						
34	South Dakota Environmental Cost Recovery Rider		188,004			188,004
35	- SD Docket EL09-009					
36						
37	South Dakota Transmission Cost Recovery Rider		300,197			300,197
38	- SD Docket EL09-009					
39						
40	Prior Flow Through Contra		163,842			163,842
41						
42						
43						
44	TOTAL	2,058,913,137	279,425,105		264,535,867	2,073,802,375

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 232 Line No.: 7 Column: d

Accounts Charged:

506 111,490
735 165,111

Schedule Page: 232 Line No.: 21 Column: d

Accounts Charged:

253 1,993,263
407.3 22,573,753
432 69,338

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

Accounts Charged:

253 370,048
407.3 2,178,555

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

Accounts Charged:

182.3 606,685
407.4 6,692,176

Schedule Page: 232 Line No.: 41 Column: d

Accounts Charged:

182.3 816,525
407.3 1,172,394
502 983,631

Schedule Page: 232.1 Line No.: 23 Column: d

Accounts Charged:

517 4,460,665
519 461,403
520 4,866,761
523 155,085
524 2,112,783
528 7,198,138
529 61,248
530 10,552,662
531 6,076,229
532 10,588,350

Schedule Page: 232.1 Line No.: 31 Column: d

Accounts Charged:

128 144,816,525
282 (40,776,065)

MISCELLANEOUS DEFERRED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	LONG-TERM ACCOUNTS					
2	RECEIVABLE					
3						
4	IPP Power Contract Billing	6,593,600		253	3,512,497	3,081,103
5	Adjustments					
6						
7	Notes Receivable - CIP Loans	-77,697		232	21,049	-98,746
8						
9	Install CIAC	5,635		142	2,646	2,989
10						
11	LONG-TERM PREPAYMENTS AND					
12	DEFERRED CHARGES					
13						
14	Debt Issuance Costs	127	673			800
15						
16	Securities Registration Costs	20,611		181	6,863	13,748
17						
18	DEBITS NOT PROVIDED FOR					
19	ELSEWHERE					
20						
21	Minnesota Electric Retail	894,343	969,803	928	799,096	1,065,050
22	Rate Case					
23	- Amortized over 48 months					
24	ending December 2012					
25						
26	Minnesota Gas Retail Rate Case	419,682	323,199	928	410,230	332,651
27	- Amortized over 36 months					
28	ending December 2012					
29						
30	North Dakota Electric Retail	200,000	37,902	928	137,902	100,000
31	Rate Case					
32	- Amortized over 36 months					
33	ending December 2010					
34						
35	North Dakota Gas Retail	96,045		Various	65,935	30,110
36	Rate Case					
37	- Amortized over 36 months					
38	ending December 2010					
39						
40	South Dakota Electric Retail		217,079			217,079
41	Rate Case					
42	- Amortized over 60 months					
43	ending December 2014					
44						
45	Regulatory Reserve	-6,593,600	3,512,497			-3,081,103
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	1,558,746				1,663,681

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	/ /	2009/Q4
FOOTNOTE DATA			

Schedule Page: 233 Line No.: 35 Column: d

Accounts Charged:

131	15,935
928	50,000

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Electric (See Electric Other)	330,366,823	348,115,259
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	330,366,823	348,115,259
9	Gas		
10	Gas (See Gas Other)	21,047,336	21,411,255
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	21,047,336	21,411,255
17	Other (Specify)	20,441,259	18,209,706
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	371,855,418	387,736,220

Notes

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

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

	Balance at Beginning of Year	Balance at End of Year
Electric (Other)		
Avoided Tax Interest	\$ 91,430,679	\$ 98,749,438
Bad Debts	9,580,059	8,360,180
Customer Advances	542,354	528,827
Deferred Connection Fees	41,187,317	43,262,658
End of Life Nuclear Fuel Amortization	15,829,839	16,920,695
Environmental Remediation	64,296	81,987
ESOP Dividends	3,412,744	3,736,878
Regulatory Difference - Effect of Rate Changes	(186,422)	108,049
Investment Tax Credit Grossup	25,014,522	23,101,577
Fuel Tax Credit - Inc Addback	82,623	5,796
Inventory Reserve	227,035	326,512
Investment Tax Credit	452,260	452,260
Medical Deductions - Self Insured	1,107,532	249,580
Monticello Rerate	580,261	458,095
Nuclear Plant - Decommissioning Provisions	52,390,180	43,800,065
Nuclear Refueling Outage Costs	5,587,292	4,217,948
Pension Expense	7,379,813	7,639,804
Post Employment Benefits - Retiree Medical	29,143,939	31,778,496
Post Employment Benefits - Workers' Compensation	6,278,881	6,133,312
R and E Credit	14,156,465	15,395,837
Rate Refund Reserve	18,713,304	26,661,121
Sale of Emission Allowances	1,114,013	914,817
Severance Accrual	152,398	232,225
State Research Credit	1,977,252	2,126,439
State Tax Deduction Cash versus Accrual	221,894	53,361
Unbilled Revenue	(3,273,178)	-
Vacation Accrual	6,470,382	6,565,687
Wind Credit	679,045	6,202,911
Workers' Compensation	50,044	50,704
	\$330,366,823	\$348,115,259

Schedule Page: 234 Line No.: 8 Column: c

Accumulated Deferred Income Taxes (Account 190). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of year accumulated deferred income taxes balances in the formula. An adjustment is made to eliminate the accumulated deferred income tax balances related to postretirement employee benefits and regulatory differences related to income taxes.

Schedule Page: 234 Line No.: 10 Column: b

	Balance at Beginning of Year	Balance at End of Year
Gas (Other)		
Avoided Tax Interest	\$ 3,828,722	\$ 3,385,182
Bad Debts	917,417	905,385
Deferred Connection Fees	7,272,320	7,598,747
Deferred Revenue	40,746	176,971
Environmental Remediation	6,157	8,879
ESOP Dividends	1,352,603	1,547,164
Regulatory Difference - Effect of Rate Changes	644,445	751,711
Investment Tax Credit Grossup	2,783,199	2,557,743
Inventory Reserve	23,224	32,214

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Lower of Cost or Market on Gas Inventories	894,419	90,437
Medical Deduction - Self Insured	129,658	19,828
Pension Expense	863,946	606,962
Post Employment Benefits - Retiree Medical	3,411,846	2,524,716
Post Employment Benefits - Workers' Compensation	735,061	487,275
Rate Refund Reserve	430,900	173,937
Severance Accrual	17,841	18,450
Unbilled Revenue	(3,068,505)	-
Vacation Accrual	757,478	521,626
Workers' Compensation	5,859	4,028
	\$ 21,047,336	\$ 21,411,255

Schedule Page: 234 Line No.: 17 Column: b

	Balance at Beginning of Year	Balance at End of Year
Nonutility		
Avoided Tax Interest	\$ 18,473	\$ 17,352
Contributions Carryover	3,872,300	4,625,084
Deferred Compensation Plan Reserve	5,483,617	2,562,084
Executive Incentive Plans	421,388	-
Regulatory Difference - Effect of Rate Changes	213	(16)
Federal NOL	7,722,926	8,979,898
Fuel Hedging	166,448	41,663
Low Income Housing Credit - Federal DIT Only	3,281,181	3,341,509
Minnesota State Only NOL	(4,637,868)	(4,340,211)
North Dakota State Only NOL	6,505	77,370
Nonqualified Pension Plans	-	2,151,711
Performance Share Plan	-	499,462
Regulatory Reserve	3,898,052	45,728
South Andover Trust Inc.	208,024	208,072
	\$ 20,441,259	\$ 18,209,706

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	Common Stock			
2	-All NSP-Minnesota common stock is owned by			
3	parent, Xcel Energy Inc.	5,000,000	0.01	
4				
5				
6				
7				
8				
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42				

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

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

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

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				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
						2
1,000,000	10,000					3
						4
						5
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OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

- (a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
- (b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
- (c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
- (d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	none	
2		
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39		
40	TOTAL	

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	none	
2		
3		
4		
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21		
22	TOTAL	

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221		
2			
3	FIRST MORTGAGE BONDS SERIES DUE:		
4			
5	7.125% July 1, 2025	250,000,000	1,898,288
6			2,330,000 D
7			
8	6.500% March 1, 2028	150,000,000	1,474,427
9			1,761,001 D
10			
11	8.500% April 1, 2030-Becker Pol Cntrl Rev Ref Ser 2000A	69,000,000	1,257,850
12			
13	8.000% Aug. 28, 2012	450,000,000	1,142,102
14			4,500,000 D
15			
16	8.500% March 1, 2019-Pollution Control Series N	27,900,000	963,532
17			
18	8.500% Sept. 1, 2019-Pollution Control Series O	50,000,000	1,039,348
19			
20	8.500% Sept. 1, 2019-Pollution Control Series P	50,000,000	1,023,693
21			
22	4.750% Aug. 1, 2010 First Mortgage Bonds	175,000,000	1,673,926
23			449,750 D
24			
25	5.250% March 1, 2018 First Mortgage Bonds	500,000,000	4,815,362
26			1,520,000 D
27			
28	5.35% November 1, 2039 First Mortgage Bonds	300,000,000	4,089,581
29			570,000 D
30			
31			
32	5.250% July 15, 2035 First Mortgage Bonds	250,000,000	3,032,114
33	TOTAL	3,272,000,000	50,910,474

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			485,000 D
2			
3	6.250% June 1, 2036 First Mortgage Bonds	400,000,000	4,877,058
4			1,404,000 D
5			
6	6.200% July 1, 2037 First Mortgage Bonds	350,000,000	4,336,843
7			1,988,000 D
8			
9	SUBTOTAL - ACCOUNT 221	3,021,900,000	46,631,875
10			
11	ACCOUNT 224 - OTHER LONG-TERM DEBT		
12			
13	5 year credit facility		
14			
15			
16	6.875% Aug. 1, 2009-Senior Notes	250,000,000	2,476,099
17			1,802,500 D
18			
19	Right of Way debt		
20			
21	8.500% Seeley Promissory Note	100,000	
22			
23	SUBTOTAL - ACCOUNT 224	250,100,000	4,278,599
24			
25	Interest on Debt to Associated Companies		
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	3,272,000,000	50,910,474

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
						3
						4
07/01/95	07/01/25	07/01/95	07/01/25	250,000,000	17,812,500	5
						6
						7
03/01/98	03/01/28	03/01/98	03/01/28	150,000,000	9,750,000	8
						9
						10
04/01/00	04/01/30	04/01/00	04/01/30	69,000,000	5,865,000	11
						12
08/28/02	08/28/12	08/28/02	08/28/12	450,000,000	36,000,000	13
						14
						15
03/01/92	03/01/19	04/01/97	03/01/19	27,900,000	2,371,500	16
						17
09/01/93	09/01/19	04/01/97	09/01/19	50,000,000	4,250,000	18
						19
09/01/93	09/01/19	04/01/97	09/01/19	50,000,000	4,250,000	20
						21
08/08/03	08/01/10	08/08/03	08/01/10	175,000,000	8,312,500	22
						23
						24
03/18/08	03/01/18	3/18/08	3/01/18	500,000,000	26,768,134	25
						26
						27
11/17/09	11/1/39	11/17/09	11/1/39	300,000,000	1,976,323	28
						29
						30
						31
07/21/05	07/15/35	07/21/05	07/15/35	250,000,000	13,125,000	32
				3,021,966,511	187,047,365	33

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
05/25/06	06/01/36	05/25/06	06/01/36	400,000,000	24,455,460	3
						4
						5
07/01/07	07/01/37	06/26/07	07/01/37	350,000,000	21,510,859	6
						7
						8
				3,021,900,000	176,447,276	9
						10
						11
						12
12/14/06	12/14/11					13
						14
						15
08/01/99	08/01/09	08/01/99	08/01/09		10,026,042	16
						17
						18
				55,445		19
						20
06/01/96	05/31/11			11,066	1,280	21
						22
				66,511	10,027,322	23
						24
					572,767	25
						26
						27
						28
						29
						30
						31
						32
				3,021,966,511	187,047,365	33

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 28 Column: a

Commission authorization per Instruction 2:

Minnesota Public Utilities Commission docket E,G-002/S-08-1180 dated Jan. 13, 2009.

Schedule Page: 256.1 Line No.: 13 Column: a

As of Dec. 31, 2009, NSP-Minnesota had in place a \$482.2 million multi-year credit facility with a maturity date of Dec. 14, 2011.

This line of credit provides short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings. The credit facility has one financial covenant requiring that the debt to total capitalization ratio be less than or equal to 65 percent. The interest rate under this line of credit is equal to the Eurodollar rate plus a margin based on NSP-Minnesota's senior unsecured long-term debt rating, or an alternative base rate.

Although the outstanding balances may be intended as short-term financing, they are classified as long term debt due to the terms of the credit facility.

Credit line fees are expensed in the period incurred and are charged to Account No. 431.

Interest paid on outstanding balances under the credit line is charged to Account No. 427.

Facility	\$ 482,222,222
Direct Borrowings	
Letters of Credit	(5,797,206)
Available	<u>\$ 476,425,016</u>

Schedule Page: 256.1 Line No.: 23 Column: a

Instruction 12

Detail for Account 224 of Net Changes during the Year

(Thousands of Dollars)

	Balance Dec. 31, 2008	Additions	Reductions	Balance Dec. 31, 2009
Senior Notes	\$ 250,000		\$(250,000)	\$ 0
Right of Way debt	86	15	(46)	55
Seeley Promissory Note	21		(10)	11
	<u>\$ 250,107</u>	<u>\$ 15</u>	<u>\$(250,056)</u>	<u>\$ 66</u>

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

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	293,770,340
2		
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	10,578,997
6	Contributions in Aid of Construction - gas surcharges	1,158,023
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		555,835,794
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		-43,049,528
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		-944,794,485
21		
22	Equity in earnings of subsidiary companies	-963,526
23		
24	Total income tax expense	174,339,203
25		
26		
27	Federal Tax Net Income	46,874,818
28	Show Computation of Tax:	
29	Federal income tax at 35 percent	16,406,186
30	Other	-33,511,885
31	Total Federal income tax payable	-17,105,699
32		
33		
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44		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2009/Q4
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 10 Column: b

DEDUCTION RECORDED ON BOOKS NOT DEDUCTED FOR RETURN:

Accounts Receivable - MISO Day 2	\$ 26,581,737
Avoided Cost Interest	28,979,208
Book Amortization - Computer Software	25,692,833
Book Amortization - Amortization Other	1,481,481
Book Depreciation	320,141,907
Book Rent Expense - Capitalized for Tax	5,290,659
Book Unamortized Cost of Reacquired Debt	2,576,740
Capitalization of Software Expense - Books	654,861
Clearing Account Book Expense	10,454,849
Club Dues	23,000
Contributions Carryover	5,424,476
Deferred Gas Costs	6,211,001
Deferred Revenue	333,333
Environmental Remediation	49,892
ESOP Dividends	1,753,388
Inventory Reserve	265,218
Lobbying Expenses	1,292,000
Meals and Entertainment	786,000
Nondeductible Interest on COLI Loans	115,000
Nonqualified External Decommissioning Fund (Stock Loss)	929,316
Nuclear Fuel Expense	80,456,265
Penalties	3,826,145
Pension and Benefit Capitalized - Medicare Reimbursement	502,480
Post Employment Benefits - Retiree Medical	4,466,413
Prepaid Insurance	1,420,737
Rate Refund Reserve	18,803,980
Regulatory Asset - Mercury Reduction	2,672,353
Regulatory Asset - RES Rider	3,659,549
Regulatory Asset - TCR Rider	418,682
Regulatory Reserve - Environmental	276,601
Severance Accrual	196,690
Suite and Entertainment Tickets	99,000
	\$ 555,835,794

Schedule Page: 261 Line No.: 15 Column: b

INCOME RECORDED ON BOOKS NOT INCLUDED IN RETURN:

AFDC Equity (Non-CIP)	\$ (29,935,609)
Book Income- Wisconsin/ South Dakota AFDC	(233,000)
Gain/(Loss) on Dispositions (Book)	(156,554)
Gain/(Loss) on Dispositions (Tax)	(9,368,317)
Nuclear Refueling Outage Costs - Regulatory Liability	(3,356,048)
	\$ (43,049,528)

Schedule Page: 261 Line No.: 20 Column: b

DEDUCTIONS ON RETURN NOT CHARGED AGAINST BOOK INCOME:

Additional Charitable Contributions	\$ (6,000)
ADR Repair Allowance	(18,291,597)
AFDC Debt (Non-CIP)	(18,812,119)
Bad Debts	(3,024,105)
Deferred Compensation Plan Reserve	(216,116)
External Qualified Nuclear Decommissioning Fund	(1,915,620)
Postretirement Benefit Medicare Reimbursements	(2,357,000)
Fuel Hedging	(305,523)
Internally Developed Software	(8,483,728)
Insurance Fund Income (Cash Value)	(4,292,000)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		//	2009/Q4

FOOTNOTE DATA

Interest Expense - Capital Leases	(987,282)
Interest Income/Expense on Disputed Tax	(1,378,440)
Mark to Market Adjustment	(1,168,242)
Medical Deduction - Self Insured	(625,411)
Nonqualified External Decommissioning Fund (Fees)	(8,417)
Nonqualified External Decommissioning Fund (Interest)	(2,290,926)
Nonqualified Pension Plan	(1,672,689)
Nuclear Decommissioning	(19,201,171)
Nuclear Refueling Outage Costs - Regulatory Asset	(20,057,471)
Partnership Passthrough	(152,223)
Pension and Benefit Capitalized	(1,139,802)
Performance Share Plan	(731,218)
Post Employment Benefits - Workers' Compensation	(968,880)
Private Fuel Storage	(10,830)
PUCIP Adjustment	(22,271,246)
Rate Case/Restructuring Expense	(134,821)
Regulatory Asset - MISO Day 2	(1,087,372)
Regulatory Asset - ECR Rider	(3,438,829)
Repair Expenditures	(64,224,580)
Regulatory Reserve	(132,544)
Sale of Emission Allowances	(488,467)
Section 174	(19,540,131)
State Tax Deduction	(21,990,872)
Tax Amortization - Monticello Rerate	(299,596)
Tax Amortization - Computer Software	(9,373,058)
Tax Amortization - Pollution Control Facilities	(21,380,514)
Tax Amortization - Prairie Island Training Center	(19,981)
Tax Depreciation	(640,166,596)
Tax Expense - Ash Ponds and Landfills	(1,175,387)
Tax Removal Cost Over Book	(26,966,730)
Vacation Accrual	(350,391)
Unbilled Revenue	(3,653,647)
Workers' Compensation	(2,913)
	<u>\$ (944,794,485)</u>

Schedule Page: 261 Line No.: 31 Column: b

Northern States Power Co. (a Minnesota corporation) is a member of an affiliated group which will file a consolidated Federal income tax return for the year 2009. The other members of the affiliated group and the Federal income tax provision of each are:

Xcel Energy Inc.	\$ (11,438,918)
NSP Nuclear Corp.	990,299
United Power and Land Co.	(38,153)
Northern States Power Co. (a Wisconsin corporation)	16,360,345
Public Service Co. of Colorado	(21,847,131)
Southwestern Public Service Co.	6,306,880
Xcel Energy Communications Group	3,194,474
Xcel Energy Markets Holdings	(160,300)
Xcel Energy International	878,884
Xcel Energy Retail Holdings	524,106
Xcel Energy Ventures	305,564
Xcel Energy Wholesale Group	4,263,405
Xcel Energy WYCO Inc.	(20,675,818)
WestGas Interstate, Inc.	35,031
Xcel Energy Services Inc.	1,470,365

The consolidated Federal income tax liability is apportioned among the member companies based on the stand-alone method. The stand-alone method allocates the consolidated Federal income tax liability among the companies based on the recognition

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	/ /	2009/Q4
FOOTNOTE DATA			

of the benefits/burdens contributed by each member to the consolidated return. Under the stand-alone method, the sum of the amounts allocated to the member companies equals the consolidated amount.

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	FEDERAL TAXES					
2	Income Tax 2009		28,642,256	-13,086,939	16,284,000	-6,681,286
3	Income Tax 2008				-62,210,452	
4	Income Tax Adjustment			-4,018,760		4,018,760
5						
6	FICA 2009			32,168,400	28,634,227	-1,349,902
7	FICA 2008	301,255			301,255	
8						
9	Unemployment 2009			299,211	290,045	-240
10	Unemployment 2008	58,705			58,705	
11						
12	Heavy Vehicle Use Tax			53,554	53,554	
13						
14	SUBTOTAL	359,960	28,642,256	15,415,466	-16,588,666	-4,012,668
15						
16	REAL ESTATE					
17	Real Estate 2009			58,763,660		
18	Real Estate 2009 directly exp			-66,436	-66,436	
19	Real Estate 2008	58,000,000		198,357	58,198,357	
20						
21	SUBTOTAL	58,000,000		58,895,581	58,131,921	
22						
23	STATE TAXES MINNESOTA					
24	Income Tax 2009		11,143,541	19,099,659	27,083,000	-33,979
25	Income Tax 2008				-5,146,758	
26	Income Tax Adjustment			-463,702		463,702
27						
28	Unemployment 2009			3,016,872	2,919,173	-434
29	Unemployment 2008	561,976			561,976	
30						
31	Personal Property 2009			51,736,420		
32	Personal Property 2008	50,000,000		-176,931	49,823,069	
33						
34	Use 2009		666,356	8,288,239	7,016,381	
35	Use prior years amendment			1,950	1,950	
36						
37	GROSS EARNINGS					
38	MINNESOTA					
39	Minneapolis 2009			15,602,345	14,308,809	
40	Minneapolis 2008	1,348,245			1,348,245	
41	TOTAL	128,562,585	40,452,222	223,797,205	192,666,408	-3,609,398

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1						
2	St Paul 2009			19,958,853	18,885,293	
3	St Paul 2008	1,235,156			1,235,156	
4						
5	South St Paul 2009			714,099	541,000	
6	South St Paul 2008	197,231			197,231	
7						
8	White Bear Lake 2009			256,994		
9	White Bear Lake 2008	258,924			258,924	
10						
11	Winona 2009			941,742	732,489	
12	Winona 2008	204,735			204,735	
13						
14	Lake City 2009			59,316		
15	Lake City 2008	73,233			73,233	
16						
17	West St Paul 2009			695,454	329,709	
18	West St Paul 2008	388,249			388,249	
19						
20	Coon Rapids 2009			608,188	557,345	
21	Coon Rapids 2008	49,501			49,501	
22						
23	FRANCHISE MINNESOTA					
24	Afton 2009			32,020	25,889	
25	Afton 2008	5,984			5,984	
26						
27	Blaine 2008		1	1		
28						
29	Brooklyn Center 2009			399,775	298,054	
30	Brooklyn Center 2008	99,149			99,149	
31						
32	Burnsville 2008	265				
33						
34	Champlin 2009			261,416	194,483	
35						
36	Chisago City 2009			37,578	20,137	
37						
38	Circle Pines 2009			3,429	2,186	
39						
40	Cottage Grove 2009			391,663	293,430	
41	TOTAL	128,562,585	40,452,222	223,797,205	192,666,408	-3,609,398

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
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Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Cottage Grove 2008	97,573			97,573	
2						
3	Deephaven 2009			47,002	35,276	
4	Deephaven 2008	11,824			11,824	
5						
6	Delano 2009			128,331	102,566	
7	Delano 2008	25,154			25,154	
8						
9	Dilworth 2009			51,550	38,439	
10	Dilworth 2008	13,212			13,212	
11						
12	East Grand Forks 2009			97,010		
13	East Grand Forks 2008	127,349			127,349	
14						
15	Excelsior 2009			46,760	35,069	
16	Excelsior 2008	11,722			11,722	
17						
18	Faribault 2009			658,905	494,641	
19	Faribault 2008	165,947			165,947	
20						
21	Goodview 2009			132,182	98,999	
22	Goodview 2008	32,212			32,212	
23						
24	Grant 2009			54,004	40,449	
25	Grant 2008	13,415			13,415	
26						
27	Hastings 2008		54	54		
28						
29	Hopkins 2009			186,964	139,709	
30	Hopkins 2008	46,224			46,224	
31						
32	Lindstrom 2009			41,022	22,272	
33						
34	Little Canada 2009			204,037	155,491	
35	Little Canada 2008	48,913			48,913	
36						
37	Mahtomedi 2009			69,102	51,785	
38	Mahtomedi 2008	17,003			17,003	
39						
40	Mankato 2009			372,120	279,932	
41	TOTAL	128,562,585	40,452,222	223,797,205	192,666,408	-3,609,398

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
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Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Mankato 2008	77,543			77,543	
2						
3	Maplewood 2009			185,692	139,182	
4	Maplewood 2008	46,413			46,413	
5						
6	Minnetonka 2009			798,645	598,439	
7	Minnetonka 2008	200,654			200,654	
8						
9	Monticello 2009			281,500	211,811	
10	Monticello 2008	67,242			67,242	
11						
12	Moorhead 2009			598,007	542,594	
13	Moorhead 2008	86,368			86,368	
14						
15	Mound 2009			109,085	81,619	
16	Mound 2008	27,374			27,374	
17						
18	Moundsview 2009			469,660	420,413	
19	Moundsview 2008	62,489			62,489	
20						
21	New Brighton 2009			525,074	472,514	
22	New Brighton 2008	57,417			57,417	
23						
24	New Hope 2008			247,532	185,498	
25	New Hope 2008	62,034			62,034	
26						
27	Newport 2009			33,916	25,426	
28	Newport 2008	8,544			8,544	
29						
30	No Mankato 2009			67,500	61,845	
31	No Mankato 2008	5,804			5,804	
32						
33	No St Paul 2009			121,374	94,202	
34	No St Paul 2008	36,246			36,246	
35						
36	Oakdale 2009			317,776	238,469	
37	Oakdale 2008	79,647			79,647	
38						
39	Owatonna 2009			12,360		
40	Owatonna 2008	12,584			12,584	
41	TOTAL	128,562,585	40,452,222	223,797,205	192,666,408	-3,609,398

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
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Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1						
2	Prior Lake 2009			98,916	74,662	
3	Prior Lake 2008	23,599			23,599	
4						
5	Richfield 2009			452,644	333,855	
6	Richfield 2008	109,828			109,828	
7						
8	Robbinsdale 2009			342,804	253,365	
9	Robbinsdale 2008	78,621			78,621	
10						
11	Sartell 2009			145,627	108,905	
12	Sartell 2008	32,541			32,541	
13						
14	Sauk Rapids 2009			355,195	271,055	
15	Sauk Rapids 2008	79,377			79,377	
16						
17	St Cloud 2009			2,328,994	1,787,194	
18	St Cloud 2008	566,446			566,446	
19						
20	St Joseph 2009			57,016	42,990	
21	St Joseph 2008	13,922			13,922	
22						
23	St Louis Park 2009			579,548	436,527	
24	St Louis Park 2008	144,369			144,369	
25						
26	St Michael 2009			166,609	126,987	
27	St Michael 2008	39,680			39,680	
28						
29	St Paul Park 2009			150,770	113,590	
30	St Paul Park 2008	38,891			38,891	
31						
32	Stillwater 2009			426,754	319,934	
33	Stillwater 2008	106,921			106,921	
34						
35	Watertown 2009			52,824	39,614	
36	Watertown 2008	13,239			13,239	
37						
38	SUBTOTAL	57,110,989	11,809,952	132,480,245	133,471,681	429,289
39						
40	STATE TAXES					
41	TOTAL	128,562,585	40,452,222	223,797,205	192,666,408	-3,609,398

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
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Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	NORTH DAKOTA					
2	Income Tax 2009	6,057,157		-110,538	337,000	-43,842
3	Income Tax 2008				-282,370	
4	Income Tax Adjustment			-17,823		17,823
5						
6	Unemployment 2009			4,761	4,746	
7	Unemployment 2008	191			191	
8						
9	Personal Property 2009			2,870,395		
10	Personal Property 2008	3,000,000		-57,304	2,942,696	
11						
12	Use 2009			16,468	13,457	
13	Use 2008	11,020			11,020	
14						
15	FRANCHISE					
16	NORTH DAKOTA					
17	Fargo 2009			2,222,820	2,011,967	
18	Fargo 2008	286,329			286,329	
19						
20	Casselton 2009			12,965	10,938	
21	Casselton 2008	2,712			2,712	
22						
23	Grand Forks 2009			1,086,440	839,297	
24	Grand Forks 2008	298,848			298,848	
25						
26	Hatton 2009			14,147	10,448	
27	Hatton 2008	4,119			4,119	
28						
29	Larimore 2009			20,951	15,885	
30	Larimore 2008	5,119			5,119	
31						
32	SUBTOTAL	9,665,495		6,063,282	6,512,402	-26,019
33						
34						
35	STATE TAXES					
36	SOUTH DAKOTA					
37	Personal Property 2009			3,200,000		
38	Personal Property 2008	3,400,000		-295,926	3,104,074	
39						
40	Unemployment 2009			6,022	6,108	
41	TOTAL	128,562,585	40,452,222	223,797,205	192,666,408	-3,609,398

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1						
2	Use 2009			351,212	326,049	
3	Use 2008	26,141			26,141	
4						
5						
6	SUBTOTAL	3,426,141		3,261,308	3,462,372	
7						
8	OTHER					
9	Kansas Unemployment 2008		14	14		
10	Colorado Unemployment			162	162	
11	Georgia Unemployment 2009			5	5	
12	Wisconsin Unemployment			1,025	1,025	
13						
14	Property tax on railroad car			26,000	21,389	
15						
16	Billed by Xcel Services Inc.:					
17	Payroll Tax			7,670,184	7,670,184	
18	Sales Tax			6	6	
19	Other Tax			1,336	1,336	
20						
21	Other and rounding			-17,409	-17,409	
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	128,562,585	40,452,222	223,797,205	192,666,408	-3,609,398

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
 6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
 7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
 8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
 9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
	2,484,029	-5,784,750			-7,302,189	2
						3
		-3,387,713			-631,047	4
						5
2,184,271		19,942,335			12,226,065	6
						7
						8
8,926		185,492			113,719	9
						10
						11
		48,884			4,670	12
						13
2,193,197	2,484,029	11,004,248			4,411,218	14
						15
						16
58,763,660		56,679,260			2,084,400	17
		-70,454			4,018	18
		196,147			2,210	19
						20
58,763,660		56,804,953			2,090,628	21
						22
						23
	14,014,103	11,708,212			7,391,447	24
						25
		-749,914			286,212	26
						27
97,265		1,870,266			1,146,606	28
						29
						30
51,736,420		40,418,320			11,318,100	31
		-138,864			-38,067	32
						33
605,502		809,912			7,478,327	34
		1,780			170	35
						36
						37
						38
1,293,536					15,602,394	39
						40
132,129,980	16,498,218	133,545,262			90,251,940	41

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.

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9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
1,073,560					19,958,853	2
						3
						4
173,099					714,099	5
						6
						7
256,994					256,994	8
						9
						10
209,253					941,742	11
						12
						13
59,316					59,316	14
						15
						16
365,745					695,454	17
						18
						19
50,843					608,188	20
						21
						22
						23
6,131					32,020	24
						25
						26
						27
						28
101,721					399,775	29
						30
						31
265						32
						33
66,933					261,416	34
						35
17,441					37,578	36
						37
1,243					3,429	38
						39
98,233					391,663	40
						41
132,129,980	16,498,218	133,545,262			90,251,940	41

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.

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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
11,726					47,002	3
						4
						5
25,765					128,331	6
						7
						8
13,111					51,550	9
						10
						11
97,010					97,010	12
						13
						14
11,691					46,760	15
						16
						17
164,264					658,905	18
						19
						20
33,183					132,182	21
						22
						23
13,555					54,004	24
						25
						26
						27
					6	28
47,255					186,964	29
						30
						31
18,750					41,022	32
						33
48,546					204,037	34
						35
						36
17,317					69,102	37
						38
						39
92,188					372,120	40
						41
132,129,980	16,498,218	133,545,262			90,251,940	41

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
46,510					185,692	3
						4
						5
200,206					798,645	6
						7
						8
69,689					281,500	9
						10
						11
55,413					598,007	12
						13
						14
27,466					109,085	15
						16
						17
49,247					469,660	18
						19
						20
52,560					525,074	21
						22
						23
62,034					247,532	24
						25
						26
8,490					33,916	27
						28
						29
5,655					67,500	30
						31
						32
27,172					121,374	33
						34
						35
79,307					317,776	36
						37
						38
12,360					12,360	39
						40
132,129,980	16,498,218	133,545,262			90,251,940	41

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
24,254					98,916	2
						3
						4
118,789					452,644	5
						6
						7
89,439					342,804	8
						9
						10
36,722					145,627	11
						12
						13
84,140					355,195	14
						15
						16
541,800					2,328,994	17
						18
						19
14,026					57,016	20
						21
						22
143,021					579,548	23
						24
						25
39,622					166,609	26
						27
						28
37,180					150,770	29
						30
						31
106,820					426,754	32
						33
						34
13,210					52,824	35
						36
						37
58,752,993	14,014,103	53,919,712			78,560,533	38
						39
						40
132,129,980	16,498,218	133,545,262			90,251,940	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
 6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
 7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
 8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
 9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
5,848,147		-49,420			-61,118	2
						3
		-14,755			-3,068	4
						5
15		2,952			1,809	6
						7
						8
2,870,395		2,023,882			846,513	9
		-40,707			-16,597	10
						11
3,011		897			15,571	12
						13
						14
						15
						16
210,853					2,222,820	17
						18
						19
2,027					12,965	20
						21
						22
247,143					1,086,440	23
						24
						25
3,699					14,147	26
						27
						28
5,066					20,951	29
						30
						31
9,190,356		1,922,849			4,140,433	32
						33
						34
						35
						36
3,200,000		3,200,000				37
		-295,926				38
						39
	86	3,733			2,289	40
132,129,980	16,498,218	133,545,262			90,251,940	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
 6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
 7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
 8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
 9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
25,163		-1,323			352,535	2
						3
						4
						5
3,225,163	86	2,906,484			354,824	6
						7
						8
		9			5	9
		101			61	10
		3			2	11
		635			390	12
						13
4,611					26,000	14
						15
						16
		7,000,950			669,234	17
		6				18
		1,221			115	19
						20
		-15,909			-1,503	21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
132,129,980	16,498,218	133,545,262			90,251,940	41

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Northern States Power Company (Minnesota)		/ /	2009/Q4
FOOTNOTE DATA			

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

Amortize regulatory reserve to income taxes	\$ 41,583
Federal income tax expense (409.1 and 409.2) accrued for long term income tax payable (Account No. 253)	(6,722,869)
	<u>\$ (6,681,286)</u>

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

g409.1	\$ (2,740,399)
409.2	(4,561,790)
	<u>\$ (7,302,189)</u>

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

Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (Account No. 242)	\$ 43,615
Federal income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (Account No. 253)	3,975,145
	<u>\$ 4,018,760</u>

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

g409.1	\$ (196,085)
409.2	(434,962)
	<u>\$ (631,047)</u>

Schedule Page: 262 Line No.: 6 Column: f

241	\$ (664,447)
253	(732,774)
C408.1	38,246
184	(1,539)
C107	10,612
	<u>\$ (1,349,902)</u>

Schedule Page: 262 Line No.: 6 Column: l

G408.1	\$ 1,711,257
N408.2	54,867
E107	8,367,030
G107	575,061
N107	6,761
C107	82,112
E108	442,278
G108	20,365
C108	14,451
143	486,545
146	37,933
163	115,034
E182.3	103,584
G182.3	18,252
184	188,844
232	369
514	(686)
524	(9)
571	2,066
588	23
921	(57)
925	(15)
	<u>\$ 12,226,065</u>

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2009/Q4
FOOTNOTE DATA			

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

241 \$ (240)

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

G408.1	\$	15,917
N408.2		510
E107		77,825
G107		5,349
N107		63
C107		764
E108		4,114
G108		189
C108		134
143		4,526
146		353
163		1,070
E182.3		963
G182.3		170
184		1,757
232		3
514		(6)
524		-
571		19
588		-
921		(1)
925		
	\$	<u>113,719</u>

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

G408.1 \$ 4,670

Schedule Page: 262 Line No.: 17 Column: l

E107	\$	914,300
G408.1		1,074,100
N408.2		96,000
	\$	<u>2,084,400</u>

Schedule Page: 262 Line No.: 18 Column: a

Taxes directly expensed to Account No. 408 without passing through an Account No. 165 prepaid or Account No. 236 liability.

Schedule Page: 262 Line No.: 18 Column: l

G408.1 \$ 4,018

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

143	\$	672
549		(564)
G408.1		2,102
	\$	<u>2,210</u>

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

Amortize regulatory reserve to income taxes	\$	(50,285)
State income tax expense (409.1 and 409.2) accrued for long term income tax payable (Account No. 253)		16,306
	\$	<u>(33,979)</u>

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

g409.1 \$ 8,379

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Northern States Power Company (Minnesota)		/ /	2009/Q4

FOOTNOTE DATA

409.2	7,383,068
	<u>\$ 7,391,447</u>

Schedule Page: 262 Line No.: 26 Column: f

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (Account No. 242)	\$ 10,908
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (Account No. 253)	452,794
	<u>\$ 463,702</u>

Schedule Page: 262 Line No.: 26 Column: l

G409.1	\$ (32,782)
409.2	318,994
	<u>\$ 286,212</u>

Schedule Page: 262 Line No.: 28 Column: f

241	\$ (434)
-----	----------

Schedule Page: 262 Line No.: 28 Column: l

G408.1	\$ 160,488
N408.2	5,146
E107	784,691
G107	53,931
N107	634
C107	7,701
E108	41,479
G108	1,910
C108	1,355
143	45,630
146	3,557
163	10,788
E182.3	9,714
G182.3	1,712
184	17,711
232	35
514	(64)
524	(1)
571	194
588	2
921	(6)
925	(1)
	<u>\$ 1,146,606</u>

Schedule Page: 262 Line No.: 31 Column: l

G408.1	\$ 11,315,100
N408.2	3,000
	<u>\$ 11,318,100</u>

Schedule Page: 262 Line No.: 32 Column: l

G408.1	\$ (38,067)
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Schedule Page: 262 Line No.: 34 Column: l

G408.1	\$ 77,300
N408.2	3,130
E107	604,961
131	38,087
143	1,277,944

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Northern States Power Company (Minnesota)		/ /	2009/Q4
FOOTNOTE DATA			

146	45,089
236 (South Dakota sales tax category)	(1,274)
421	(61)
431	285,286
Accounts payable system - see note	5,147,865
	<u>\$ 7,478,327</u>

Sales and use tax accounting follows the final use of the materials or services.

Schedule Page: 262 Line No.: 35 Column: I

G408.1	\$ 170
--------	--------

Schedule Page: 262 Line No.: 37 Column: a

In 2005 NSP-Minnesota implemented a new customer billing system and changed its method of accounting for franchise fees and gross earnings taxes. Fees and taxes are not booked through the income statement and are instead recorded as a debit to Account No. 142 Customer Accounts Receivable and a credit to Account No. 236 Taxes Accrued.

Schedule Page: 262.5 Line No.: 2 Column: f

State income tax expense (409.1 and 409.2) accrued for long term	\$ (43,842)
income tax payable (Account No. 253)	

Schedule Page: 262.5 Line No.: 2 Column: I

g409.1	\$ (20,173)
409.2	(40,945)
	<u>\$ (61,118)</u>

Schedule Page: 262.5 Line No.: 4 Column: f

State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (Account No. 242)	\$ 294
State income tax expense (409.1 and 409.2) accrued liability for uncertain tax positions (Account No. 253)	17,529
	<u>\$ 17,823</u>

Schedule Page: 262.5 Line No.: 4 Column: I

g409.1	\$ (877)
409.2	(2,191)
	<u>\$ (3,068)</u>

Schedule Page: 262.5 Line No.: 6 Column: I

G408.1	\$ 253
N408.2	8
E107	1,238
G107	85
N107	1
C107	12
E108	66
G108	3
C108	2
143	72
146	6
163	17
E182.3	15
G182.3	3
184	28
	<u>\$ 1,809</u>

Schedule Page: 262.5 Line No.: 9 Column: I

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2009/Q4
FOOTNOTE DATA			

G408.1 \$ 846,513

Schedule Page: 262.5 Line No.: 10 Column: I

G408.1 \$ (16,597)

Schedule Page: 262.5 Line No.: 12 Column: I

G408.1	\$	85
241		1,668
421		(3,167)
488		21
Accounts payable system - see note		16,964
	\$	<u>15,571</u>

Sales and use tax accounting follows the final use of the materials or services.

Schedule Page: 262.5 Line No.: 40 Column: I

G408.1	\$	320
N408.2		10
E107		1,566
G107		108
N107		1
C107		16
E108		83
G108		4
C108		3
143		91
146		7
163		22
E182.3		20
G182.3		3
184		35
	\$	<u>2,289</u>

Schedule Page: 262.6 Line No.: 2 Column: I

G408.1	\$	(125)
151		42,028
236 (Minnesota sales tax category)		1,274
488		(191)
Accounts payable system - see note		309,549
	\$	<u>352,535</u>

Sales and use tax accounting follows the final use of the materials or services.

Schedule Page: 262.6 Line No.: 9 Column: I

G408.1	\$	1
E107		4
	\$	<u>5</u>

Schedule Page: 262.6 Line No.: 10 Column: I

G408.1	\$	9
E107		42
G107		3
E108		2
143		2
163		1
E182.3		1
184		1

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2009/Q4
FOOTNOTE DATA			

\$	61
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Schedule Page: 262.6 Line No.: 11 Column: I

G408.1	\$	1
E107		1
	\$	2

Schedule Page: 262.6 Line No.: 12 Column: I

G408.1	\$	55
N408.2		2
E107		267
G107		18
C107		3
E108		14
G108		1
143		15
146		1
163		4
E182.3		3
G182.3		1
184		6
	\$	390

Schedule Page: 262.6 Line No.: 14 Column: a

Property tax on railroad cars used to transport coal from mines to electric generating plants.

Schedule Page: 262.6 Line No.: 14 Column: e

Wyoming	\$	15,270
Montana		6,098
Indiana		21
	\$	21,389

Schedule Page: 262.6 Line No.: 14 Column: I

151	\$	26,000
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Schedule Page: 262.6 Line No.: 17 Column: I

G408.1	\$	617,793
N408.2		51,441
	\$	669,234

Schedule Page: 262.6 Line No.: 19 Column: I

G408.1	\$	115
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Schedule Page: 262.6 Line No.: 21 Column: I

G408.1	\$	(1,503)
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	182,602				26,774	
4	7%						
5	10%	35,886,408				2,755,497	
6							
7							
8	TOTAL	36,069,010				2,782,271	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Gas Utility						
12	4%	73,393				14,232	
13	10%	3,942,362				313,610	
14	TOTAL	4,015,755				327,842	
15	Common Utility						
16	4%	11,930				1,109	
17	10%	157,029				8,290	
18	TOTAL	168,959				9,399	
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48	Utility & Non-Util	40,253,724				3,119,512	

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
			2
155,828			3
			4
33,130,911			5
			6
			7
33,286,739			8
			9
			10
			11
59,161			12
3,628,752			13
3,687,913			14
			15
10,821			16
148,739			17
159,560			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
37,134,212			48

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 266 Line No.: 8 Column: h

Accumulated Deferred Investment Tax Credits (Account 255). The formula excludes this account because the Company has chosen to utilize the amortization of tax credits against taxable income, that is, income tax expense is reduced by the amount of the amortized investment tax credit.

Schedule Page: 266 Line No.: 18 Column: h

(a) Common Allocation

Electric - 91.44%	145,902
Gas - 8.56%	<u>13,658</u>
	159,560

OTHER DEFERRED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	LONG-TERM OBLIGATIONS FOR					
2	DEFERRED COMPENSATION					
3	PROGRAMS					
4	Unfunded Nonqualified					
5	Pension Benefit Costs	5,998,655	Various	4,819,204	4,648,295	5,827,746
6	Deferred Compensation					
7	Employees	1,898,131	Various	652,995	807,813	2,052,949
8	Employees (Wealth Op)	4,587,921	Various	846,627	475,693	4,216,987
9						
10	LONG-TERM ACCRUALS FOR					
11	OTHER EXPENSE ITEMS					
12	Postemployment Benefit -					
13	Injury Compensation	17,170,792	Various	3,837,157	2,868,277	16,201,912
14	Environmental & Regulatory					
15	Reserves	244,450	Various	132,544		111,906
16	Nuclear Waste Strategy					
17	Coalition	18,297	232	86,559	105,126	36,864
18	Affordable Housing					
19	Investment	5,249	426.5	5,249		
20	Renewable Development Fund	34,325,098	232	24,273,318	16,000,000	26,051,780
21	Rate Rider Over Collections	6,954,505			4,903,025	11,857,530
22	Long-Term Income Tax					
23	& Interest Payable	8,394,096	Various	5,440,355		2,953,741
24						
25	LONG-TERM DEPOSITS, ADVANCE					
26	BILLING & RECEIPTS					
27	Deposits - Landfill Power	290,709	131	12	1,165	291,862
28	Customer Prepayments	71,076			39,630	110,706
29	Deferred Revenue	99,750	Various	1,032,417	1,365,750	433,083
30	Tax Credit & Interest	1,746,668			252,501	1,999,169
31						
32	CREDITS NOT PROVIDED FOR					
33	ELSEWHERE					
34	IPP Power Contract Billing					
35	Adjustments	6,593,600	186	3,512,497		3,081,103
36	Wholesale Merger					
37	Settlement	84,386				84,386
38	Pre-Funded AFUDC - Metro					
39	Emissions Reduction Rider	75,978,867	Various	2,653,402	3,227,458	76,552,923
40	Pre-Funded AFUDC - Mercury					
41	Emission Reduction Rider	780,479	405	37,817		742,662
42	Pre-Funded AFUDC -					
43	Transmission Cost					
44	Recovery Rider	9,304,709	405	231,668	3,413,506	12,486,547
45	Pre-Funded AFUDC -					
46	FERC Transmission	7,105	405	99	68,434	75,440
47	TOTAL	192,778,030		48,807,422	58,876,456	202,847,064

OTHER DEFERRED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Pre-Funded AFUDC -					
2	Renewable Energy					
3	Standard Rider	7,219,528	405	289,747		6,929,781
4	NMC Long-Term Incentive	921,904	Various	582,649		339,255
5	Mark-to-Market Adjustment	3,003,925			2,343,013	5,346,938
6	Long-Term Income Tax					
7	Payable	411,300			6,750,405	7,161,705
8	Long-Term Income Tax					
9	Interest Payable	32,008			202,438	234,446
10	Mankato Energy Center Lease					
11	Normalization	13,228,422			6,785,550	20,013,972
12	Long Term Payroll Tax Liabilit				732,774	732,774
13	Regulatory Reserve	-6,593,600	186	373,106	3,885,603	-3,081,103
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	**Footnote from page 106b**					
43						
44						
45						
46						
47	TOTAL	192,778,030		48,807,422	58,876,456	202,847,064

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 269 Line No.: 5 Column: c

Accounts Charged:

232	4,394,691
174	345,407
571	79,106

Schedule Page: 269 Line No.: 7 Column: c

Accounts Charged:

131	314,184
146	56,750
232	45,465
426.5	236,596

Schedule Page: 269 Line No.: 8 Column: c

Accounts Charged:

232	778,443
426.5	68,184

Schedule Page: 269 Line No.: 13 Column: c

Accounts Charged:

146	3,124,512
165	19,389
184	166,000
232	527,256

Schedule Page: 269 Line No.: 15 Column: c

Account Charged:

108	46,232
242	49,892
426.5	1,544
735	34,876

Schedule Page: 269 Line No.: 23 Column: c

Accounts Charged:

232	280,255
242	(55,286)
282	470
409	4,382,126
409.1	434,962
409.2	(316,803)
431	(859,994)
419	1,574,625

Schedule Page: 269 Line No.: 29 Column: c

Accounts Charged:

456	666,667
495	365,750

Schedule Page: 269 Line No.: 39 Column: c

Accounts Charged:

405	2,653,401
419.1	1

Schedule Page: 269 Line No.: 46 Column: d

The amount reported is a jurisdictional amount. Use \$9,974 (non-jurisdictionalized amount) to calculate the Midwest ISO formula rate under attachment O of the Northern States Power Company FERC Tariff.

Schedule Page: 269 Line No.: 46 Column: e

The amount reported is a jurisdictional amount. Use \$3,951,508 (non-jurisdictionalized amount) to calculate the Midwest ISO formula rate under attachment O of the Northern States Power Company FERC Tariff.

Schedule Page: 269.1 Line No.: 4 Column: c

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr)	
Northern States Power Company (Minnesota)		/ /	2009/Q4
FOOTNOTE DATA			

Accounts Charged:

232 745,862
920 (163,213)

Schedule Page: 269.1 Line No.: 42 Column: f

Other Deferred Credits (Account 253). The Form 1 reports the other deferred credits balances at the beginning of year and at the end of the year. Included in this account is the credit for pre-funded AFUDC on CWIP related to the specific transmission projects that are included in the formula. The net pre-funded AFUDC amount is a total NSP system number (not jurisdictionalized). The company uses the average of the beginning of the year and at the end of the year balances as a reduction to rate base in the formula.

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	7,079,027	8,447,207	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	7,079,027	8,447,207	
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)	7,079,027	8,447,207	
18	Classification of TOTAL			
19	Federal Income Tax	7,028,156	6,586,438	
20	State Income Tax	50,871	1,860,769	
21	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
				282	1,934,858	17,461,092	4
							5
							6
							7
					1,934,858	17,461,092	8
							9
							10
							11
							12
							13
							14
							15
							16
					1,934,858	17,461,092	17
							18
						13,614,594	19
					1,934,858	3,846,498	20
							21

NOTES (Continued)

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
FOOTNOTE DATA			

Schedule Page: 272 Line No.: 8 Column: k

Accumulated Deferred Income Taxes (Account 281). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of year accumulated deferred income taxes balances in the formula.

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,129,791,732	149,106,498	
3	Gas	112,734,936	14,919,971	
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,242,526,668	164,026,469	
6	Non-Operating	229,240		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	1,242,755,908	164,026,469	
10	Classification of TOTAL			
11	Federal Income Tax	988,889,839	137,280,675	
12	State Income Tax	253,866,069	26,745,794	
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
		see note	102,508,549	182.3 & 254	152,462,339	1,328,852,020	2
		see note	4,819,783	182.3 & 254	1,174,843	124,009,967	3
							4
			107,328,332		153,637,182	1,452,861,987	5
250,610					289,140	768,990	6
							7
							8
250,610			107,328,332		153,926,322	1,453,630,977	9
							10
205,277			72,233,148		104,770,207	1,158,912,850	11
45,333			35,095,184		49,156,115	294,718,127	12
							13

NOTES (Continued)

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
FOOTNOTE DATA			

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

Account Nos. 182.3, 254, 281 and 282

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

Accumulated Deferred Income Taxes (Account 282). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of year accumulated deferred income taxes balances in the formula.

Schedule Page: 274 Line No.: 3 Column: g

Account Nos. 182.3, 254, 281 and 282

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric	77,372,863	48,399,320	28,540,546
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	77,372,863	48,399,320	28,540,546
10	Gas			
11	Gas	15,249,935	11,628,534	10,586,638
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	15,249,935	11,628,534	10,586,638
18	Non Operating	-466,856		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	92,155,942	60,027,854	39,127,184
20	Classification of TOTAL			
21	Federal Income Tax	71,984,766	47,754,794	30,824,238
22	State Income Tax	20,171,176	12,273,060	8,302,946
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
		see note	1,793	see note	526,394	97,756,238	3
							4
							5
							6
							7
							8
			1,793		526,394	97,756,238	9
							10
				283	-361,727	15,930,104	11
							12
							13
							14
							15
							16
					-361,727	15,930,104	17
83,816	34,260			see note	1,041,771	624,471	18
83,816	34,260		1,793		1,206,438	114,310,813	19
							20
65,105	26,194		13		937,213	89,891,433	21
18,711	8,066		1,780		269,225	24,419,380	22
							23

NOTES (Continued)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 276 Line No.: 3 Column: g

Account Nos. 182.3 and 283

Schedule Page: 276 Line No.: 3 Column: i

Account Nos. 182.3 and 283

Schedule Page: 276 Line No.: 9 Column: k

Accumulated Deferred Income Taxes (Account 283). The Form 1 reports the accumulated deferred income taxes balances at the beginning of the year and at the end of the year. The Company uses the average of the beginning of the year and the end of year accumulated deferred income taxes balances in the formula.

Schedule Page: 276 Line No.: 18 Column: i

Account Nos. 219.1 and 283

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	INCOME TAX ITEMS					
2	ITC Gross-up to Pre-Tax Rate Levels	27,797,723	190	2,138,402		25,659,321
3						
4	Deferred Tax Collected in Rates in Excess					
5	of Current Tax Accrual Levels	30,787,249			2,004,943	32,792,192
6						
7	Deferrals of IRS/State Interest/Other Credits	1,736,118	Various	434,029		1,302,089
8						
9	OTHER INCOME ITEMS DEFERRED DUE TO					
10	EXPECTED RATE FLOWBACK					
11	Gas Pipeline Refunds	(7,155)	142	6		-7,161
12						
13	Gain from Sales of Emission Allowances					
14	- MN Docket E-002/GR-05-1428	2,727,208	411.8	548,918	60,451	2,238,741
15						
16	Rates Collected in Excess of Low Income					
17	Discounts Provided to Customers	3,943,104	Various	9,623,786	8,314,645	2,633,963
18	- MN Electric E-002/M-03-1557					
19	- MN Gas G-002/GR-06-1429					
20						
21	Pre-ARO Decommissioning Expense	1,261,349,493			27,744,273	1,289,093,766
22						
23	Derivatives and Hedging - Retail Electric	23,354,923	Various	2,484,260		20,870,663
24						
25	Nuclear Outage Accounting	13,678,217	456	3,356,049		10,322,168
26	- MN Docket E-002/M-07-1489					
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	1,365,366,880		18,585,450	38,124,312	1,384,905,742

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2009/Q4
FOOTNOTE DATA			

Schedule Page: 278 Line No.: 7 Column: c

Accounts Charged:

419	451,021
409.1	(8,703)
928	(8,289)

Schedule Page: 278 Line No.: 14 Column: f

Gains on sale of Emissions Allowances:

Reconcile gains reported on p 114-7, 229, and 278

	p 114-7 Income Account Acct No.	p 278 Regulatory Liabilities Acct No. 254	p 229 Gain on Sale
Dec. 31, 2008	411.8	<u>(2,727,208)</u>	
Amortize past years' gains to income	(548,918)	548,918	
System gains during 2009		(77,953)	(77,953)
less portion due NSP-Wisconsin based on energy used		11,615	
less portion due SMPMPA		5,887	5,887
less gains from allowances relating to a plant owned by NSP-Wisconsin			1,299
subtotal 2009 gains	<u>(548,918)</u>	<u>488,467</u>	<u>(70,767)</u>
Dec. 31, 2009		<u>(2,238,741)</u>	

Page 114 and 278 gains are shared between NSP-Minnesota and NSP-Wisconsin based on the portion of energy that each use from the total NSP System. Page 229 reports only the gains relating to plants owned by NSP-Minnesota.

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

Accounts Charged:

232	344,412
440	9,279,374

Schedule Page: 278 Line No.: 23 Column: c

Accounts Charged:

175	(25,572,354)
219	23,354,922
245	4,701,692

ELECTRIC OPERATING REVENUES (Account 400)

- 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.
- Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
- 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.
- 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.
- Disclose amounts of \$250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,022,122,510	1,012,483,706
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,175,402,687	1,202,039,698
5	Large (or Ind.) (See Instr. 4)	588,034,006	631,636,128
6	(444) Public Street and Highway Lighting	24,512,231	23,713,562
7	(445) Other Sales to Public Authorities	8,053,286	7,981,575
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	413,671	564,002
10	TOTAL Sales to Ultimate Consumers	2,818,538,391	2,878,418,671
11	(447) Sales for Resale	181,250,252	275,780,479
12	TOTAL Sales of Electricity	2,999,788,643	3,154,199,150
13	(Less) (449.1) Provision for Rate Refunds	39,772,157	5,313,331
14	TOTAL Revenues Net of Prov. for Refunds	2,960,016,486	3,148,885,819
15	Other Operating Revenues		
16	(450) Forfeited Discounts	4,488,049	5,644,443
17	(451) Miscellaneous Service Revenues	2,132,679	2,070,964
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	3,957,116	4,127,903
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	417,028,384	437,577,575
22	(456.1) Revenues from Transmission of Electricity of Others	79,945,669	74,908,775
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	507,551,897	524,329,660
27	TOTAL Electric Operating Revenues	3,467,568,383	3,673,215,479

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
10,011,783	10,098,859	1,211,531	1,196,159	2
				3
15,190,439	15,703,207	149,116	142,402	4
9,314,647	10,143,576	482	507	5
161,199	161,246	3,771	3,708	6
87,782	92,096	2,170	2,213	7
				8
9,072	7,005			9
34,774,922	36,205,989	1,367,070	1,344,989	10
4,687,029	5,247,495			11
39,461,951	41,453,484	1,367,070	1,344,989	12
				13
39,461,951	41,453,484	1,367,070	1,344,989	14

Line 12, column (b) includes \$ 16,524,573 of unbilled revenues.
 Line 12, column (d) includes 193,225 MWH relating to unbilled revenues

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2009/Q4
FOOTNOTE DATA			

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

Commercial and industrial sales are classified as "Large" for purposes of this report if the customer has a twelve month average minimum registered demand of 1,000 kilowatts or more.

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

Commercial and industrial sales are classified as "Large" for purposes of this report if the customer has a twelve month average minimum registered demand of 1,000 kilowatts or more.

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

Connection charges	\$ 2,182,414
NSF check charges	182,943
Bad debt concession	(335,937)
Other	103,259
	<u>\$ 2,132,679</u>

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

Connection charges	\$ 1,930,932
NSF check charges	188,963
Bad debt concession	(204,583)
Other	155,652
	<u>\$ 2,070,964</u>

Schedule Page: 300 Line No.: 19 Column: b

Rent from Electric Property (Account 454). The rent revenue credit from electric property included in the formula is income directly related to transmission facilities, such as pole attachments, rentals and special use.

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

Includes reimbursement from Northern States Power Co. (a Wisconsin corporation) for production and transmission costs shared under the Interchange Agreement between the companies restated Jan. 16, 2001.

Fixed Production Expense	\$167,643,083
Variable Production Expense	184,953,647
Transmission Expense	36,426,139

Also includes the following items:

Conservation Improvement Program incentive	14,190,184
Fees charged to burn Refuse Derived Fuel	5,928,860
Windsor source program revenue	5,203,624
Manitoba Hydro Transmission path re-assignment, energy service agreement and Tatanka transmission fees	4,078,232
Amortization of Regulatory Liability relating to Nuclear Outage accounting change	3,359,848
Twin Cities Hydro distribution wheeling service revenue	624,743
Third party billings	447,517
Minnesota Cellnet labor charges	403,936
Hazardous Waste processing revenue	351,364
Great River Energy construction reimbursement and O&M fees	272,956
Provision for refund under Minnesota jurisdiction Service Quality Plan	(340,120)
Net distribution of commodity trading margins under Joint Operating Agreement	(7,503,858)

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Other

988,229

\$417,028,384**Schedule Page: 300 Line No.: 21 Column: c**

Includes reimbursement from Northern States Power Co. (a Wisconsin corporation) for production and transmission costs shared under the Interchange Agreement between the companies restated Jan. 16, 2001.

Fixed Production Expense	\$ 151,118,446
Variable Production Expense	207,055,470
Transmission Expense	31,969,257

Also includes the following items:

Net distribution of commodity trading margins under Joint Operating Agreement	31,710,295
Conservation Improvement Program incentive	13,976,253
Fees charged to burn Refuse Derived Fuel	5,759,205
Windsor source program revenue	4,537,968
Third party billings	1,213,937
Tatanka transmission fees	870,155
EEl mutual aid revenue	807,927
Refund of 2005 MISO schedule 16/17 costs	729,825
Hazardous waste processing revenue	514,765
Outdoor lighting project contributions	382,818
Southern Minnesota Municipal Power ancillary service revenue and Manitoba Hydro transmission path re-assignment	325,472
Seagate lease	301,320
Provision for refund under Minnesota jurisdiction Service Quality Plan	(323,969)
Net MISO market Financial Transmission Rights activity	(662,452)
Nuclear outage refund liability	(13,678,217)
Other	969,100
	<u>\$ 437,577,575</u>

Schedule Page: 300 Line No.: 1 Column: \$

Includes \$10,258,765 of wholesale unbilled revenue.

Schedule Page: 300 Line No.: 1 Column: MWH

Includes 194,268 Mwh of wholesale unbilled sales.

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					
2					
3					
4					
5					
6					
7					
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37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	A00, D00,E00 Water Htg	226	21,550	51	4,431	0.0954
2	A01,D01,E01 Res	5,863,389	599,420,641	799,966	7,330	0.1022
3	A02,D02,E02 Res TOD	2,590	225,667	163	15,890	0.0871
4	A03,D03,E03 Res Underground	4,044,086	411,708,227	396,821	10,191	0.1018
5	A04,D04,E04 Res TOD Under	1,902	176,494	116	16,397	0.0928
6	E06 Res Heat Pump	1,373	82,975	81	16,951	0.0604
7	A05,D05,E10 Energy-Control	34,077	1,932,912	2,401	14,193	0.0567
8	A06,D10,E11 Ltd Off-Peak	4,166	241,888	474	8,789	0.0581
9	A07,D11,E12 Auto Prot Ltg	7,447	1,238,693	11,458	650	0.1663
10	Margin sharing		4,389,659			
11	Low income discounts collected		-4,420,011			
12	Unbilled	52,527	7,103,815			0.1352
13	Total Residential	10,011,783	1,022,122,510	1,211,531	8,264	0.1021
14						
15	A05,D05,E10 Energy-Control	3,331	181,429	132	25,235	0.0545
16	A06,D10,E11 Ltd Off-Peak	3,713	254,027	137	27,102	0.0684
17	A07,D11,E12 Auto Prot Ltg	29,449	4,271,869	14,777	1,993	0.1451
18	A09 Small Gen Svc	37	12,118	106	349	0.3275
19	A10,D12,E13 Small Gen Svc	1,147,806	114,590,689	74,341	15,440	0.0998
20	A11,D13,E05 Water Heating	322	30,890	103	3,126	0.0959
21	A12,D13,E14Sm Gen TOD	48,152	4,188,736	2,718	17,716	0.0870
22	A13,D15 Direct Current	7	15,506	8	875	2.2151
23	A14,D16,E15 General Service	9,380,879	738,445,170	43,238	216,959	0.0787
24	A15,D17,E16 Gen Svc TOD	8,037,422	522,289,714	3,543	2,268,536	0.0650
25	A16,D19 Sm Gen TOD Kwh metered	14,436	1,468,865	2,656	5,435	0.1018
26	A18,D18,E18 Sm Gen TOD	29,871	2,886,867	4,738	6,305	0.0966
27	A22,D34 Sm Gen TOD Low Wattage	2,288	235,838	560	4,086	0.1031
28	A20,D20,E20 Peak Control	101,311	6,899,460	143	708,469	0.0681
29	A21,D21,E21 Pk Control TOD	210,866	11,459,395	27	7,809,852	0.0543
30	A23 Pk Cntl Tiered	1,305,799	97,720,155	1,785	731,540	0.0748
31	A24 Pk Cntl Tier TOD	3,087,654	191,137,293	442	6,985,643	0.0619
32	A27,D22 Tier 1 Energy Control	680,528	34,782,164	111	6,130,883	0.0511
33	E22 Energy Controlled	55,418	2,855,671	30	1,847,267	0.0515
34	A43 St. Anthony Falls	24	1,228			0.0512
35	A63 Experimental Real Time Pr	410,574	19,906,346	3	136,858,000	0.0485
36	Margin sharing		10,819,583			
37	Prior period corrections		-203,174			
38	Low income discounts collected		-590,685			
39	Unbilled	-44,801	-222,461			0.0050
40	TOTAL Comm & Industrial	24,505,086	1,763,436,693	149,598	163,806	0.0720
41	TOTAL Billed	34,773,880	2,812,272,583	1,367,070	25,437	0.0809
42	Total Unbilled Rev.(See Instr. 6)	1,042	6,265,808	0	0	6.0133
43	TOTAL	34,774,922	2,818,538,391	1,367,070	25,438	0.0811

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2	A30,D30,E30 St Ltg Comp-Owned	67,490	17,750,557	1,603	42,102	0.2630
3	A31 Street Lighting System	30	3,032	7	4,286	0.1011
4	A32,D31,E31 St Ltg Cust-Owned	56,784	4,068,826	577	98,412	0.0717
5	A34,D33,E32 St-Ltg Metered Cust	36,579	2,572,247	1,464	24,986	0.0703
6	A35,D32,E33 Ornmntl St Ltg Cust	1,600	104,980	119	13,445	0.0656
7	A37 St Ltg-Saint Paul	1,347	193,182	1	1,347,000	0.1434
8	Margin sharing		72,593			
9	Low income discounts collected		-5,972			
10	Unbilled	-2,631	-247,214			0.0940
11	Total Street & Hwy Lighting	161,199	24,512,231	3,771	42,747	0.1521
12						
13	A40,D40 Small Muni Pump	7,512	791,490	922	8,148	0.1054
14	A41,D41 Muni Pump	84,323	7,569,730	654	128,934	0.0898
15	A42,D42,E40 Fire Siren		35,398	594		
16	Margin sharing		32,287			
17	Low income discounts collected		-7,287			
18	Unbilled	-4,053	-368,332			0.0909
19	TOTAL Other Sales	87,782	8,053,286	2,170	40,453	0.0917
20						
21	Interdepartmental Sales	9,072	413,671			0.0456
22	Unbilled					
23	TOTAL Interdepartmental Sales	9,072	413,671			0.0456
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	34,773,880	2,812,272,583	1,367,070	25,437	0.0809
42	Total Unbilled Rev.(See Instr. 6)	1,042	6,265,808	0	0	6.0133
43	TOTAL	34,774,922	2,818,538,391	1,367,070	25,438	0.0811

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 304 Line No.: 10 Column: a

Pursuant to orders by the Minnesota Public Utilities Commission and the North Dakota Public Service Commission, NSP-Minnesota shares profit and loss on sales of power from plants owned by NSP Minnesota, and margins on sales of purchased power with retail customers in those states. The margins are returned through the retail fuel clause.

Schedule Page: 304 Line No.: 11 Column: a

See page 278 Other Regulatory Liabilities, "Rates collected in excess of low income discounts provided to customers".

This amount has been transferred from revenue to the Regulatory Liability for the electric low income discount plan.

Schedule Page: 304 Line No.: 36 Column: a

Pursuant to orders by the Minnesota Public Utilities Commission and the North Dakota Public Service Commission, NSP-Minnesota shares profit and loss on sales of power from plants owned by NSP Minnesota, and margins on sales of purchased power with retail customers in those states. The margins are returned through the retail fuel clause.

Schedule Page: 304 Line No.: 38 Column: a

See page 278 Other Regulatory Liabilities, "Rates collected in excess of low income discounts provided to customers".

This amount has been transferred from revenue to the Regulatory Liability for the electric low income discount plan.

Schedule Page: 304.1 Line No.: 8 Column: a

Pursuant to orders by the Minnesota Public Utilities Commission and the North Dakota Public Service Commission, NSP-Minnesota shares and loss on sales of power from plants owned by NSP Minnesota, and margins on sales of purchased power with retail customers in those states. The margins are returned through the retail fuel clause.

Schedule Page: 304.1 Line No.: 9 Column: a

See page 278 Other Regulatory Liabilities, "Rates collected in excess of low income discounts provided to customers".

This amount has been transferred from revenue to the Regulatory Liability for the electric low income discount plan.

Schedule Page: 304.1 Line No.: 16 Column: a

Pursuant to orders by the Minnesota Public Utilities Commission and the North Dakota Public Service Commission, NSP-Minnesota shares and loss on sales of power from plants owned by NSP Minnesota, and margins on sales of purchased power with retail customers in those states. The margins are returned through the retail fuel clause.

Schedule Page: 304.1 Line No.: 17 Column: a

See page 278 Other Regulatory Liabilities, "Rates collected in excess of low income discounts provided to customers".

This amount has been transferred from revenue to the Regulatory Liability for the electric low income discount plan.

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).

2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Central Minnesota Municipal Power Agenc	RQ	V6	N/A	N/A	N/A
2	City of Ada	RQ	RS474	N/A	N/A	N/A
3	City of Fairfax	RQ	RS477	N/A	N/A	N/A
4	City of Kasota	RQ	RS478	N/A	N/A	N/A
5	City of Kasson	RQ	RS479	N/A	N/A	N/A
6	Heartland Consumers Power District	RQ	V6	N/A	N/A	N/A
7	Missouri River Energy Services	RQ	V6	N/A	N/A	N/A
8	New Ulm Public Utilities	RQ	RS398	N/A	N/A	N/A
9	North Central Power	RQ	RS459	N/A	N/A	N/A
10	NSP-Wisconsin	RQ		N/A	N/A	N/A
11	Northwestern Wisconsin Electric	RQ	RS451	N/A	N/A	N/A
12	Shakopee Public Utilities	RQ	RS486	N/A	N/A	N/A
13	Sleepy Eye Utility	RQ	V6	N/A	N/A	N/A
14	Unbilled	RQ		N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).

2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

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 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Ameren Energy	SF	MCRSG	N/A	N/A	N/A
2	Big Rivers Electric	SF	MCRSG	N/A	N/A	N/A
3	Blue Earth	OS	RS470	N/A	N/A	N/A
4	Central Minnesota Municipal Power Agen	OS	RS470	N/A	N/A	N/A
5	City of Delano CMMPA	OS	RS470	N/A	N/A	N/A
6	City of Fairfax CMMPA	OS	RS470	N/A	N/A	N/A
7	City of Glencoe CMMPA	OS	RS470	N/A	N/A	N/A
8	City of Granite Falls CMMPA	OS	RS470	N/A	N/A	N/A
9	City of Janesville CMMPA	OS	RS470	N/A	N/A	N/A
10	City of Kenyon CMMPA	OS	RS470	N/A	N/A	N/A
11	City of Mountain Lake CMMPA	OS	RS470	N/A	N/A	N/A
12	City of Springfield CMMPA	OS	RS470	N/A	N/A	N/A
13	City of Windom CMMPA	OS	RS470	N/A	N/A	N/A
14	DTE Energy Trading	OS	V6	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).

2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
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 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	Duke Energy Indiana	OS	V6	N/A	N/A	N/A
2	First Energy Solutions	SF	MCRSG	N/A	N/A	N/A
3	GEN-SYS Energy	SF	MCRSG	N/A	N/A	N/A
4	Great River Energy	OS	V6	N/A	N/A	N/A
5	Great River Energy	SF	V6	N/A	N/A	N/A
6	Integrus Energy Services	OS	V6	N/A	N/A	N/A
7	Kansas City Power and Light Co	OS	V6	N/A	N/A	N/A
8	Louisville Gas and Electric	SF	MCRSG	N/A	N/A	N/A
9	Manitoba Hydro	SF	V6	N/A	N/A	N/A
10	Manitoba Hydro	SF	MCRSG	N/A	N/A	N/A
11	MidAmerican Energy	SF	MCRSG	N/A	N/A	N/A
12	Midwest Independent System Operator	OS	V6	N/A	N/A	N/A
13	Midwest Independent System Operator	AD	V6	N/A	N/A	N/A
14	Missouri River Energy Services	SF	MCRSG	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
	86,400			86,400	1
50		2,130		2,130	2
12		851		851	3
800		29,600		29,600	4
145,450		3,403,696		3,403,696	5
	1,137,500			1,137,500	6
68,007		2,420,074		2,420,074	7
8		468		468	8
14,048		313,907		313,907	9
24		1,411		1,411	10
371		36,919		36,919	11
2,478,038		87,228,351	1,642,010	88,870,361	12
-55,256		-2,118,616		-2,118,616	13
5		899		899	14
7,364,202	7,277,221	315,522,700	-1,294,483	321,505,438	
3,966,760	3,919,400	146,682,194	-7,319,523	143,282,071	
11,330,962	11,196,621	462,204,894	-8,614,006	464,787,509	

SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
	1,858,500			1,858,500	1
83		12,294		12,294	2
128,300		6,806,617		6,806,617	3
438,234		19,500,608		19,500,608	4
		205,742		205,742	5
7		2,064		2,064	6
	367,000			367,000	7
668,058		24,570,403		24,570,403	8
800		16,000		16,000	9
-73,183			-8,961,533	-8,961,533	10
					11
					12
					13
					14
7,364,202	7,277,221	315,522,700	-1,294,483	321,505,438	
3,966,760	3,919,400	146,682,194	-7,319,523	143,282,071	
11,330,962	11,196,621	462,204,894	-8,614,006	464,787,509	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 310 Line No.: 1 Column: j

Customer charge.

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

Customer charge.

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

Customer charge.

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

Customer charge.

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

Customer charge.

Schedule Page: 310 Line No.: 6 Column: j

Customer charge.

Schedule Page: 310 Line No.: 7 Column: j

Customer charge.

Schedule Page: 310 Line No.: 8 Column: j

Customer charge.

Schedule Page: 310 Line No.: 9 Column: j

Customer charge.

Schedule Page: 310 Line No.: 10 Column: a

Ownership interest or affiliation per Instruction 2:

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both wholly owned operating subsidiaries of Xcel Energy Inc.

Schedule Page: 310 Line No.: 11 Column: j

Customer charge.

Schedule Page: 310 Line No.: 12 Column: j

Customer charge.

Schedule Page: 310 Line No.: 13 Column: j

Customer charge.

Schedule Page: 310 Line No.: 14 Column: j

Unbilled activity.

Schedule Page: 310.2 Line No.: 12 Column: j

Ancillary Services.

Schedule Page: 310.3 Line No.: 10 Column: j

Unbilled activity.

Schedule Page: 310.3 Line No.: 11 Column: a

Total revenue and volumes sold will not match pages 300-1, line 11, due to differences in accounting classification associated with the Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) Interchange

	Revenue	Mwh
page 300, line 11(b)	\$ 181,250,252	4,687,029
page 311 total (k)	\$ 464,787,509	11,330,962
less net interchange agreement	(283,537,257)	(6,643,933)
	\$ 181,250,252	4,687,029

Schedule Page: 310.3 Line No.: 12 Column: k

Sales for Resale (Account 447). The revenue credit from sales for resale included in the formula are for bundled sales that are not included in the formula divisor.

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	5,504,816	6,214,010
5	(501) Fuel	346,163,445	361,095,059
6	(502) Steam Expenses	25,623,673	17,948,987
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	5,086,782	5,932,583
10	(506) Miscellaneous Steam Power Expenses	18,619,808	20,711,490
11	(507) Rents	4,053,075	5,228,307
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	405,051,599	417,130,436
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,870,752	1,958,952
16	(511) Maintenance of Structures	6,509,408	7,376,114
17	(512) Maintenance of Boiler Plant	33,744,693	35,945,387
18	(513) Maintenance of Electric Plant	5,955,478	12,173,312
19	(514) Maintenance of Miscellaneous Steam Plant	14,667,342	14,101,094
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	62,747,673	71,554,859
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	467,799,272	488,685,295
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	55,496,919	36,731,492
25	(518) Fuel	92,085,127	76,752,261
26	(519) Coolants and Water	6,035,232	5,555,018
27	(520) Steam Expenses	35,549,432	27,772,772
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	2,173,923	2,445,144
31	(524) Miscellaneous Nuclear Power Expenses	112,945,299	98,171,210
32	(525) Rents	4,890,473	2,500,052
33	TOTAL Operation (Enter Total of lines 24 thru 32)	309,176,405	249,927,949
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	11,319,965	8,914,034
36	(529) Maintenance of Structures	478,277	349,621
37	(530) Maintenance of Reactor Plant Equipment	26,921,321	18,642,685
38	(531) Maintenance of Electric Plant	11,975,527	6,195,186
39	(532) Maintenance of Miscellaneous Nuclear Plant	22,493,682	14,454,783
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	73,188,772	48,556,309
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	382,365,177	298,484,258
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	21	1,320
45	(536) Water for Power		-186
46	(537) Hydraulic Expenses	501	204
47	(538) Electric Expenses	254,721	234,609
48	(539) Miscellaneous Hydraulic Power Generation Expenses	136,657	129,751
49	(540) Rents	10,157	20,346
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	402,057	386,044
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	610	8,446
54	(542) Maintenance of Structures	34,225	82,055
55	(543) Maintenance of Reservoirs, Dams, and Waterways	146,638	260,373
56	(544) Maintenance of Electric Plant	68,395	52,346
57	(545) Maintenance of Miscellaneous Hydraulic Plant	6,897	2,742
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	256,765	405,962
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	658,822	792,006

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	1,272,067	844,969
63	(547) Fuel	101,859,496	102,298,570
64	(548) Generation Expenses	2,589,742	2,427,682
65	(549) Miscellaneous Other Power Generation Expenses	6,079,462	4,978,992
66	(550) Rents	1,123,677	1,011,137
67	TOTAL Operation (Enter Total of lines 62 thru 66)	112,924,444	111,561,350
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	435,340	186,092
70	(552) Maintenance of Structures	4,408,721	2,078,136
71	(553) Maintenance of Generating and Electric Plant	9,513,057	5,402,217
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	306,873	227,665
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	14,663,991	7,894,110
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	127,588,435	119,455,460
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	784,529,558	1,041,992,866
77	(556) System Control and Load Dispatching	498,785	99,512
78	(557) Other Expenses	54,527,012	106,517,615
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	839,555,355	1,148,609,993
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,817,967,061	2,056,027,012
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,474,597	4,412,242
84	(561) Load Dispatching	5,833	
85	(561.1) Load Dispatch-Reliability	132,571	533,491
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	5,461,713	5,537,839
87	(561.3) Load Dispatch-Transmission Service and Scheduling	45,752	47,928
88	(561.4) Scheduling, System Control and Dispatch Services	6,672,851	6,688,949
89	(561.5) Reliability, Planning and Standards Development	507,346	606,555
90	(561.6) Transmission Service Studies	-3,913	-5,347
91	(561.7) Generation Interconnection Studies	31,089	22,982
92	(561.8) Reliability, Planning and Standards Development Services	479,796	520,953
93	(562) Station Expenses	999,202	988,029
94	(563) Overhead Lines Expenses	1,881,222	1,214,278
95	(564) Underground Lines Expenses	11,322	1,287
96	(565) Transmission of Electricity by Others	78,771,852	67,969,184
97	(566) Miscellaneous Transmission Expenses	47,288,902	44,891,883
98	(567) Rents	2,660,515	2,618,697
99	TOTAL Operation (Enter Total of lines 83 thru 98)	151,420,650	136,048,950
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	158,281	121,906
102	(569) Maintenance of Structures	3,480	899
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	5,450,881	4,240,539
108	(571) Maintenance of Overhead Lines	6,577,792	6,599,869
109	(572) Maintenance of Underground Lines	2,914	65
110	(573) Maintenance of Miscellaneous Transmission Plant	295,648	65,881
111	TOTAL Maintenance (Total of lines 101 thru 110)	12,488,996	11,029,159
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	163,909,646	147,078,109

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	137,867	231,820
116	(575.2) Day-Ahead and Real-Time Market Facilitation	237,469	5,965
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation	230,136	
120	(575.6) Market Monitoring and Compliance	57,352	
121	(575.7) Market Facilitation, Monitoring and Compliance Services	11,634,632	9,746,447
122	(575.8) Rents	37,418	20,486
123	Total Operation (Lines 115 thru 122)	12,334,874	10,004,718
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	12,334,874	10,004,718
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	8,988,253	8,587,770
135	(581) Load Dispatching	5,666,065	5,272,785
136	(582) Station Expenses	2,515,464	2,481,727
137	(583) Overhead Line Expenses	1,238,407	602,858
138	(584) Underground Line Expenses	5,995,906	6,218,566
139	(585) Street Lighting and Signal System Expenses	1,965,934	1,816,460
140	(586) Meter Expenses	2,800,597	2,939,367
141	(587) Customer Installations Expenses	2,260,197	2,877,813
142	(588) Miscellaneous Expenses	14,732,521	15,641,371
143	(589) Rents	2,563,602	2,847,940
144	TOTAL Operation (Enter Total of lines 134 thru 143)	48,726,946	49,286,657
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	678,785	504,641
147	(591) Maintenance of Structures	699	
148	(592) Maintenance of Station Equipment	6,182,010	5,152,322
149	(593) Maintenance of Overhead Lines	34,560,603	35,672,906
150	(594) Maintenance of Underground Lines	9,103,259	9,000,754
151	(595) Maintenance of Line Transformers	1,706,248	1,683,233
152	(596) Maintenance of Street Lighting and Signal Systems	1,494,291	1,521,843
153	(597) Maintenance of Meters	70,400	111,395
154	(598) Maintenance of Miscellaneous Distribution Plant	6,449	1,719
155	TOTAL Maintenance (Total of lines 146 thru 154)	53,802,744	53,648,813
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	102,529,690	102,935,470
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	252,547	256,483
160	(902) Meter Reading Expenses	20,370,920	20,380,433
161	(903) Customer Records and Collection Expenses	25,889,153	25,131,454
162	(904) Uncollectible Accounts	14,379,366	18,758,034
163	(905) Miscellaneous Customer Accounts Expenses	94,507	111,534
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	60,986,493	64,637,938

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		
168	(908) Customer Assistance Expenses	60,022,607	59,684,949
169	(909) Informational and Instructional Expenses	1,563,629	1,293,266
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	61,586,236	60,978,215
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	164,155	152,452
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	164,155	152,452
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	54,229,392	44,731,423
182	(921) Office Supplies and Expenses	38,811,786	39,276,794
183	(Less) (922) Administrative Expenses Transferred-Credit	14,840,987	15,860,300
184	(923) Outside Services Employed	12,124,999	19,979,489
185	(924) Property Insurance	9,858,965	5,364,982
186	(925) Injuries and Damages	11,018,252	11,095,583
187	(926) Employee Pensions and Benefits	65,535,754	54,623,670
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	5,465,375	5,406,314
190	(929) (Less) Duplicate Charges-Cr.	3,316,854	3,096,710
191	(930.1) General Advertising Expenses	2,886,342	3,755,011
192	(930.2) Miscellaneous General Expenses	2,911,022	2,969,817
193	(931) Rents	13,397,329	12,818,377
194	TOTAL Operation (Enter Total of lines 181 thru 193)	198,081,375	181,064,450
195	Maintenance		
196	(935) Maintenance of General Plant	444,243	476,860
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	198,525,618	181,541,310
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,418,003,773	2,623,355,224

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 320 Line No.: 78 Column: b

Includes \$43,292,759 of fixed costs and \$20,766,714 of variable costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for production costs shared through the Interchange Agreement.

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through an Interchange Agreement.

Schedule Page: 320 Line No.: 78 Column: c

Includes \$40,914,989 of fixed costs and \$23,280,397 of variable costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for production costs shared through the Interchange Agreement.

Northern States Power Co. (a Minnesota corporation) and Northern States Power Co. (a Wisconsin corporation) are both operating utility subsidiaries of Xcel Energy Inc. The two companies coordinate the operation and maintenance of their electric generation and transmission systems through an Interchange Agreement.

Schedule Page: 320 Line No.: 97 Column: b

Includes \$45,192,114 of fixed costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for transmission costs shared through the Interchange Agreement.

Schedule Page: 320 Line No.: 97 Column: c

Includes \$42,167,323 of fixed costs reimbursed to Northern States Power Co. (a Wisconsin corporation) for transmission costs shared through the Interchange Agreement.

Schedule Page: 320 Line No.: 112 Column: b

Total Transmission Expense as reported in the Form 1, page 321, line 112 is reduced by amounts related to transactions with an affiliated Company based on the approved Interchange Agreement.

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Agassiz Beach, LLC	OS		N/A	N/A	N/A
2	Agassiz Beach, LLC	AD		N/A	N/A	N/A
3	Ameren Corp.	AD		N/A	N/A	N/A
4	Barron County Incinerator	OS		N/A	N/A	N/A
5	Barron County Incinerator	AD		N/A	N/A	N/A
6	Big Rivers Electric Corp.	AD		N/A	N/A	N/A
7	Bisson Windfarm, LLC	OS		N/A	N/A	N/A
8	Bisson Windfarm, LLC	AD		N/A	N/A	N/A
9	Boeve Windfarm, LLC	OS		N/A	N/A	N/A
10	Boeve Windfarm, LLC	AD		N/A	N/A	N/A
11	Calpine Corporation	OS		N/A	N/A	N/A
12	Cannon Falls Energy Center	OS		N/A	N/A	N/A
13	Cannon Falls Energy Center	AD		N/A	N/A	N/A
14	Cargill-Power Markets, LLC	OS		N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Carleton College	OS		N/A	N/A	N/A
2	CG Windfarm, LLC	OS		N/A	N/A	N/A
3	CG Windfarm, LLC	AD		N/A	N/A	N/A
4	Chanarambie Power Partners, LL	OS		N/A	N/A	N/A
5	Chanarambie Power Partners, LL	AD		N/A	N/A	N/A
6	Cisco Wind Energy, LLC	OS		N/A	N/A	N/A
7	Cisco Wind Energy, LLC	AD		N/A	N/A	N/A
8	City of Ames, Iowa	AD		N/A	N/A	N/A
9	City of Hastings	OS		N/A	N/A	N/A
10	City of Hastings	AD		N/A	N/A	N/A
11	City of St Cloud	OS		N/A	N/A	N/A
12	Columbia, Missouri Water & Lig	AD		N/A	N/A	N/A
13	Connexus Energy	OS		N/A	N/A	N/A
14	Connexus Energy	AD		N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Constellation Energy Commoditi	OS		N/A	N/A	N/A
2	Consumers Energy Co.	AD		N/A	N/A	N/A
3	Covanta Hennepin Energy Resour	OS		N/A	N/A	N/A
4	Covanta Hennepin Energy Resour	AD		N/A	N/A	N/A
5	Dairyland Electric Cooperative	OS		N/A	N/A	N/A
6	Darrell & Shirley Houselog	OS		N/A	N/A	N/A
7	Detroit Edison Co.	AD		N/A	N/A	N/A
8	DTE Energy	OS		N/A	N/A	N/A
9	Duke Energy Indiana, Inc.	AD		N/A	N/A	N/A
10	Duke Energy Kentucky, Inc.	AD		N/A	N/A	N/A
11	East Kentucky Power Coop, Inc.	AD		N/A	N/A	N/A
12	East Ridge	OS		N/A	N/A	N/A
13	East Ridge	AD		N/A	N/A	N/A
14	Eau Galle Renewable Energy Co.	OS		N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Ed Olsen Wind Farm, LLC	OS		N/A	N/A	N/A
2	Ewington Energy System, LLC	OS		N/A	N/A	N/A
3	Ewington Energy System, LLC	AD		N/A	N/A	N/A
4	Fenton Power Partners, LLC	OS		N/A	N/A	N/A
5	Fenton Power Partners, LLC	AD		N/A	N/A	N/A
6	Fey Windfarm, LLC	OS		N/A	N/A	N/A
7	Fey Windfarm, LLC	AD		N/A	N/A	N/A
8	FibroMinn, LLC	OS		N/A	N/A	N/A
9	FibroMinn, LLC	AD		N/A	N/A	N/A
10	FirstEnergy Solutions Corp.	AD		N/A	N/A	N/A
11	FPL Energy Mower County, LLC	OS		N/A	N/A	N/A
12	FPL Energy Mower County, LLC	AD		N/A	N/A	N/A
13	Garwin McNeilus	OS		N/A	N/A	N/A
14	Garwin McNeilus	AD		N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	GFI Group Inc.	OS		N/A	N/A	N/A
2	Great River Energy	OS		N/A	N/A	N/A
3	Great River Energy	AD		N/A	N/A	N/A
4	Hilltop Power, LLC	OS		N/A	N/A	N/A
5	ICAP Energy LLC	OS		N/A	N/A	N/A
6	Indianapolis Power & Light Co.	AD		N/A	N/A	N/A
7	Integrays Energy Services Inc	OS		N/A	N/A	N/A
8	InterContinental Exchange	OS		N/A	N/A	N/A
9	Jeffers Wind Energy Center	OS		N/A	N/A	N/A
10	Jeffers Wind Energy Center	AD		N/A	N/A	N/A
11	JJN Windfarm, LLC	OS		N/A	N/A	N/A
12	JJN Windfarm, LLC	AD		N/A	N/A	N/A
13	Kas Brothers Windfarm, LLC	OS		N/A	N/A	N/A
14	K-Brink Windfarm, LLC	OS		N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	K-Brink Windfarm, LLC	AD		N/A	N/A	N/A
2	KODA Energy, LLC	OS		N/A	N/A	N/A
3	Lac Courte Oreilles Hydro	OS		N/A	N/A	N/A
4	Lac Courte Oreilles Hydro	AD		N/A	N/A	N/A
5	Lake Benton II Power Partners,	OS		N/A	N/A	N/A
6	Lake Benton Power Partners, LL	OS		N/A	N/A	N/A
7	Laurentian Energy Authority, L	OS		N/A	N/A	N/A
8	Leone Meyer - Kenetech	OS		N/A	N/A	N/A
9	Lois Johnson	AD		N/A	N/A	N/A
10	LSP Cottage Grove Inc.	OS		N/A	N/A	N/A
11	LSP Cottage Grove Inc.	AD		N/A	N/A	N/A
12	Madison Gas & Electric Co.	AD		N/A	N/A	N/A
13	Manitoba Hydro Electric Board	OS		N/A	N/A	N/A
14	Mankato Energy Center, LLC	OS		N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Mankato Energy Center, LLC	AD		N/A	N/A	N/A
2	Merle & Marilyn Johnson	AD		N/A	N/A	N/A
3	Metro Wind, LLC	OS		N/A	N/A	N/A
4	Metro Wind, LLC	AD		N/A	N/A	N/A
5	MidAmerican Energy Holdings Co.	AD		N/A	N/A	N/A
6	Midwest ISO	OS		N/A	N/A	N/A
7	Midwest ISO	AD		N/A	N/A	N/A
8	MinnDakota Wind, LLC	OS		N/A	N/A	N/A
9	MinnDakota Wind, LLC	AD		N/A	N/A	N/A
10	Minnesota Methane, LLC	OS		N/A	N/A	N/A
11	Minnesota Methane, LLC	AD		N/A	N/A	N/A
12	Minnesota Municipal Power Agen	OS		N/A	N/A	N/A
13	Minnesota Power Inc.	OS		N/A	N/A	N/A
14	Minnkota Power Cooperative Inc.	OS		N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Minnkota Power Cooperative Inc.	AD		N/A	N/A	N/A
2	Minwind Energy, LLC	OS		N/A	N/A	N/A
3	Minwind Energy, LLC	AD		N/A	N/A	N/A
4	Miscellaneous	OS		N/A	N/A	N/A
5	Montana-Dakota Utilities Co.	AD		N/A	N/A	N/A
6	Moraine Wind II, LLC	OS		N/A	N/A	N/A
7	Moraine Wind, LLC	OS		N/A	N/A	N/A
8	Moraine Wind, LLC	AD		N/A	N/A	N/A
9	NAE Lakota Ridge LLC	OS		N/A	N/A	N/A
10	NAE Shaokatan, LLC	OS		N/A	N/A	N/A
11	NAE Shaokatan, LLC	AD		N/A	N/A	N/A
12	Nebraska Public Power District	AD		N/A	N/A	N/A
13	Neshkoro Power Associates, Inc	OS		N/A	N/A	N/A
14	Neshkoro Power Associates, Inc	OS		N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	New England ISO	OS		N/A	N/A	N/A
2	New England ISO	AD		N/A	N/A	N/A
3	New Ulm Public Utilities Commi	OS		N/A	N/A	N/A
4	New York ISO	OS		N/A	N/A	N/A
5	New York ISO	AD		N/A	N/A	N/A
6	Norgaard North	OS		N/A	N/A	N/A
7	Norgaard North	AD		N/A	N/A	N/A
8	Norgaard South	OS		N/A	N/A	N/A
9	Norgaard South	AD		N/A	N/A	N/A
10	Northern Indiana Pub Service C	AD		N/A	N/A	N/A
11	Omaha Public Power District	AD		N/A	N/A	N/A
12	Otter Tail Power Co.	OS		N/A	N/A	N/A
13	Pine Bend Landfill	OS		N/A	N/A	N/A
14	Pine Bend Landfill	AD		N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	PJM Interconnection LLC	OS		N/A	N/A	N/A
2	PJM Interconnection LLC	AD		N/A	N/A	N/A
3	Rapidan Hydroelectric Facility	OS		N/A	N/A	N/A
4	Rapidan Hydroelectric Facility	AD		N/A	N/A	N/A
5	Rock Ridge Power Partners, LLC	OS		N/A	N/A	N/A
6	Ruthton Ridge LLC	OS		N/A	N/A	N/A
7	Ruthton Ridge LLC	AD		N/A	N/A	N/A
8	Sempra Energy	OS		N/A	N/A	N/A
9	Shane's Wind Machine LLC	OS		N/A	N/A	N/A
10	Shane's Wind Machine LLC	AD		N/A	N/A	N/A
11	Silver Bay Power Co.	OS		N/A	N/A	N/A
12	Silver Bay Power Co.	AD		N/A	N/A	N/A
13	South Ridge Power Partners, LL	OS		N/A	N/A	N/A
14	St. Olaf College	OS		N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	St. Olaf College	AD		N/A	N/A	N/A
2	St. Paul Cogeneration	OS		N/A	N/A	N/A
3	St. Paul Cogeneration	AD		N/A	N/A	N/A
4	Stahl Wind Group	OS		N/A	N/A	N/A
5	TG Windfarm, LLC	OS		N/A	N/A	N/A
6	TG Windfarm, LLC	AD		N/A	N/A	N/A
7	Tholen Transmission-Trust	OS		N/A	N/A	N/A
8	Tholen Transmission-Trust	AD		N/A	N/A	N/A
9	Tofteland Windfarm, LLC	OS		N/A	N/A	N/A
10	Tofteland Windfarm, LLC	AD		N/A	N/A	N/A
11	Tullet Prebon	OS		N/A	N/A	N/A
12	Uiik Wind Farm, LLC	OS		N/A	N/A	N/A
13	Upper Peninsula Power Co.	AD		N/A	N/A	N/A
14	Velva Windfarm, LLC	OS		N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Viking Wind Partners	OS		N/A	N/A	N/A
2	Viking Wind Partners	AD		N/A	N/A	N/A
3	Western Area Power Administrat	OS		N/A	N/A	N/A
4	Western Area Power Administrat	AD		N/A	N/A	N/A
5	Westridge Windfarm, LLC	OS		N/A	N/A	N/A
6	Westridge Windfarm, LLC	AD		N/A	N/A	N/A
7	Windcurrent Farms, LLC	OS		N/A	N/A	N/A
8	Windcurrent Farms, LLC	AD		N/A	N/A	N/A
9	Windpower Partners 1993, LP	OS		N/A	N/A	N/A
10	Windvest Power Partners, LLC	OS		N/A	N/A	N/A
11	Windvest Power Partners, LLC	AD		N/A	N/A	N/A
12	Wisconsin Electric Power	OS		N/A	N/A	N/A
13	Wisconsin Public Service Corp.	AD		N/A	N/A	N/A
14	Woodstock Hills, LLC	OS		N/A	N/A	N/A
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
4,900				200,110		200,110	1
-11				-463		-463	2
				2,519		2,519	3
15				970		970	4
2							5
				575		575	6
5,140				174,749		174,749	7
29				1,013		1,013	8
4,892				163,939		163,939	9
11				64		64	10
				-511,890		-511,890	11
28,939			23,063,765	4,675,620		27,739,385	12
			-295,067	186,885		-108,182	13
					-2,127	-2,127	14
16,546,660			168,367,696	611,180,010	4,981,852	784,529,558	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
3,962				130,677		130,677	1
4,971				168,983		168,983	2
133				4,538		4,538	3
223,428				5,907,116		5,907,116	4
				-3,208		-3,208	5
19,541				955,580		955,580	6
-2,522				-41,387		-41,387	7
				133		133	8
26,035			563,532	514,658		1,078,190	9
				45		45	10
43,495			1,350,254	862,212		2,212,466	11
				24		24	12
				574		574	13
				126		126	14
16,546,660			168,367,696	611,180,010	4,981,852	784,529,558	

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.

- 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.
- For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
- 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.
- 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.
- 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.
- 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)	
			1,140,000			1,140,000	1
				359		359	2
187,055			8,302,584	3,748,078		12,050,662	3
			1,869	1,359,332		1,361,201	4
17,522				161,255		161,255	5
				1,000		1,000	6
				1,193		1,193	7
					-2,075	-2,075	8
				972		972	9
				51		51	10
				479		479	11
24,904				821,679		821,679	12
1,046				34,446		34,446	13
1				141		141	14
16,546,660			168,367,696	611,180,010	4,981,852	784,529,558	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
3,541				120,381		120,381	1
55,569				2,444,904		2,444,904	2
				134,903		134,903	3
675,968				26,518,261		26,518,261	4
				18,918		18,918	5
5,080				177,759		177,759	6
2				60		60	7
394,447				47,039,748		47,039,748	8
				1,113,441		1,113,441	9
-2				1,796		1,796	10
280,965				11,397,392		11,397,392	11
				46,458		46,458	12
82,291				2,688,952		2,688,952	13
309				10,151		10,151	14
16,546,660			168,367,696	611,180,010	4,981,852	784,529,558	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
					3,136	3,136	1
213,600			16,250	5,572,824		5,589,074	2
				2,158		2,158	3
4,304				212,210		212,210	4
					3,242	3,242	5
-1				1,452		1,452	6
					-2,086	-2,086	7
					172	172	8
130,942				5,333,433		5,333,433	9
-13,268				173,760		173,760	10
4,290				143,691		143,691	11
4				120		120	12
3,782				134,261		134,261	13
4,913				164,611		164,611	14
16,546,660			168,367,696	611,180,010	4,981,852	784,529,558	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
10				188		188	1
72,622				4,429,499		4,429,499	2
2,351							3
429							4
275,284				7,585,784		7,585,784	5
251,982				6,733,772		6,733,772	6
286,768				30,397,529		30,397,529	7
				4,652		4,652	8
				4,652		4,652	9
258,510			36,224,253	10,013,381		46,237,634	10
				309,990		309,990	11
				115		115	12
3,998,067			41,919,040	111,292,275		153,211,315	13
337,542			33,118,956	20,408,106		53,527,062	14
16,546,660			168,367,696	611,180,010	4,981,852	784,529,558	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
			391,609	24,721		416,330	1
				4,652		4,652	2
871				35,621		35,621	3
8				335		335	4
				7,407		7,407	5
5,414,233				169,207,150		169,207,150	6
-22,661				-8,067,474		-8,067,474	7
511,783				20,691,891		20,691,891	8
211				8,237		8,237	9
9,148				411,660		411,660	10
			-380,812	533,126		152,314	11
			384,000			384,000	12
4,800			36,000	353,963		389,963	13
311,307			12,862,461	4,390,752		17,253,213	14
16,546,660			168,367,696	611,180,010	4,981,852	784,529,558	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
				-282,682		-282,682	1
32,947				1,099,175		1,099,175	2
356				-224		-224	3
				44,347	17,408	61,755	4
-1				26		26	5
152,913				8,458,125		8,458,125	6
141,830				4,303,109		4,303,109	7
-195				-7,652		-7,652	8
27,106				1,389,203		1,389,203	9
63,678				2,937,907		2,937,907	10
-261				-10,687		-10,687	11
				1,504		1,504	12
7,215			289,948	148,155		438,103	13
2,222			74,052	45,933		119,985	14
16,546,660			168,367,696	611,180,010	4,981,852	784,529,558	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
132,725				7,199,586		7,199,586	1
50				22,184		22,184	2
			284,250			284,250	3
454,297				20,454,451		20,454,451	4
				-489		-489	5
13,190				435,320		435,320	6
32				1,081		1,081	7
10,729				354,129		354,129	8
25				804		804	9
				51		51	10
				1,295		1,295	11
				39,028	4,948,736	4,987,764	12
49,820			1,030,850	1,024,018		2,054,868	13
9			15,678	203		15,881	14
16,546,660			168,367,696	611,180,010	4,981,852	784,529,558	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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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)	
661,227				23,106,351		23,106,351	1
55				-2,558		-2,558	2
21,055			368,022	443,883		811,905	3
-60				-1,226		-1,226	4
6,776				223,558		223,558	5
47,073				1,922,889		1,922,889	6
-99				-4,098		-4,098	7
					13,478	13,478	8
6,440				212,524		212,524	9
23				742		742	10
156,580			6,590,202	3,116,714		9,706,916	11
				194,964		194,964	12
6,655				219,635		219,635	13
22				739		739	14
16,546,660			168,367,696	611,180,010	4,981,852	784,529,558	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
1				30		30	1
155,257				23,704,057		23,704,057	2
				61,397		61,397	3
24,281				801,310		801,310	4
5,006				170,191		170,191	5
86				2,926		2,926	6
42,745				1,410,590		1,410,590	7
							8
2,625				89,244		89,244	9
-263				-8,913		-8,913	10
					1,968	1,968	11
78				1,950		1,950	12
				1		1	13
30,420				1,003,904		1,003,904	14
16,546,660			168,367,696	611,180,010	4,981,852	784,529,558	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
36,742				1,212,473		1,212,473	1
-63				-1,993		-1,993	2
11,808				340,970		340,970	3
-11				-5,789		-5,789	4
4,531				154,026		154,026	5
121				4,114		4,114	6
5,347				187,223		187,223	7
152				5,318		5,318	8
53,710				2,024,287		2,024,287	9
4,627				152,708		152,708	10
-1							11
			1,016,000			1,016,000	12
-2				411		411	13
21,540				1,020,783		1,020,783	14
16,546,660			168,367,696	611,180,010	4,981,852	784,529,558	

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Ada, City of	Western Area Power	Ada, City of	OLF
2	East Grand Forks, City of	Western Area Power	East Grand Forks	OS
3	Fairfax, City of	Western Area Power	Fairfax, City of	OS
4	Granite Falls, City of	Western Area Power	Granite Falls, City of	OS
5	Great River Energy	Various	Various	OS
6	Hillsboro, City of	Western Area Power	Hillsboro, City of	OLF
7	Marshall, City of	WAPA & Heartland	Marshall, City of	OLF
8	Minnesota Municipal Power Agency	Various	Various	LFP
9	Sauk Centre, City of	Western Area Power	Sauk Centre, City of	OLF
10	Sioux Falls, City of	Western Area Power	Sioux Falls, City of	OS
11	Sleepy Eye, City of	Western Area Power	Sleepy Eye, City of	OLF
12	South Dakota State Penitentiary (SDSP)	Western Area Power	SDSP	OS
13	Southern MN Municipal Power Agency	Various	Various	OS
14	St James, City of	Western Area Power	St James, City of	OLF
15	United Power Association	Various	Various	OLF
16	University of North Dakota	Western Area Power	University of North Dakota	OS
17	Wisconsin Public Power, Inc. (WPPI)	MP	WPPI	OS
18	Midwest ISO	Various	Various	OS
19	Net Unbilled Revenue			
20				
21	**Footnote from page 106b**			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.

7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
474	Western Area Power	Ada, City of	1	25,214	24,622	1
483	Western Area Power	East Grand Forks,				2
477	Western Area Power	Fairfax, City of	2	13,355	13,041	3
436	Western Area Power	Granite Falls,				4
MISO OATT	Various	Various				5
414	Western Area Power	Hillsboro, City of	4	29,573	28,881	6
403	WAPA, Heartland	Marshall, City of	77	615,133	600,716	7
TM-1	Various	Various	164	1,042,104	1,017,680	8
449	Western Area Power	Sauk Centre, City of	10	65,469	63,936	9
484	Western Area Power	Sioux Falls, City of				10
393	Western Area Power	Sleepy Eye, City of	8	48,585	47,446	11
385	Western Area Power	SDSP				12
MISO OATT	Various	Various				13
412	Western Area Power	St James, City of	9	58,732	57,356	14
PP-63-4	Various	Various				15
440	Western Area Power	UND				16
NSP Tar Vol 3	BOSWE44G22.8	WPPI-West				17
MISO OATT	Various	Various				18
0						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			275	1,898,165	1,853,678	

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

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

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
39,541		8,691	48,232	1
		43,600	43,600	2
901		1,784	2,685	3
		13,788	13,788	4
26,123,829		126,993	26,250,822	5
67,445		12,778	80,223	6
1,272,362		148,688	1,421,050	7
2,556,912		306,285	2,863,197	8
160,061		29,534	189,595	9
		153,966	153,966	10
23,837		5,624	29,461	11
		12,752	12,752	12
4,633,006			4,633,006	13
152,309		28,026	180,335	14
		8,040,000	8,040,000	15
		53,429	53,429	16
		37,440	37,440	17
22,771,228		12,973,787	35,745,015	18
949		146,124	147,073	19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
57,802,380	0	22,143,289	79,945,669	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 328 Line No.: 1 Column: d

No termination date - 3 year notice

Schedule Page: 328 Line No.: 1 Column: m

Ancillary service charge

Schedule Page: 328 Line No.: 2 Column: m

Facilities charge

Schedule Page: 328 Line No.: 3 Column: d

No termination date - 3 year notice

Schedule Page: 328 Line No.: 3 Column: m

Ancillary service charge

Schedule Page: 328 Line No.: 4 Column: m

Facilities charge

Schedule Page: 328 Line No.: 5 Column: d

Joint Zonal Revenue Agreement

Schedule Page: 328 Line No.: 5 Column: m

Facilities charge

Schedule Page: 328 Line No.: 6 Column: d

No termination date - 4 year notice

Schedule Page: 328 Line No.: 6 Column: m

Ancillary service charge

Schedule Page: 328 Line No.: 7 Column: d

No termination date - 4 year notice

Schedule Page: 328 Line No.: 7 Column: m

Ancillary service charge

Schedule Page: 328 Line No.: 8 Column: d

Termination date 08-30-2012

Schedule Page: 328 Line No.: 8 Column: m

Ancillary service charge

Schedule Page: 328 Line No.: 9 Column: d

No termination date - 2 year notice

Schedule Page: 328 Line No.: 9 Column: m

Ancillary service charge

Schedule Page: 328 Line No.: 10 Column: m

Facilities charge

Schedule Page: 328 Line No.: 11 Column: d

No termination date - 4 year notice

Schedule Page: 328 Line No.: 11 Column: m

Ancillary service charge

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

Facilities charge

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

Joint Zonal Revenue Agreement

Schedule Page: 328 Line No.: 14 Column: d

No termination date - 4 year notice

Schedule Page: 328 Line No.: 14 Column: m

Ancillary service charge

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

Presidential Permit 63-4. Termination date 04-30-2015

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

Facilities charge

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

Facilities charge

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

Meter charge

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 328 Line No.: 18 Column: d

NSP share of zonal revenues from Midwest ISO regional OAT.

Schedule Page: 328 Line No.: 18 Column: m

Ancillary service charge

Schedule Page: 328 Line No.: 19 Column: m

Net unbilled revenue is the difference between unbilled revenue at the beginning of the year and unbilled revenue at the end of the year.

Schedule Page: 328 Line No.: 21 Column: n

Revenues from Transmission of Electricity of Others (Account 456.1). The revenue credit from transmission of electricity of others included in the formula are from loads that are not included in the formula divisor, and for transmission charges associated with Schedule 26 of the MISO OATT.

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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25					
26					
27					
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32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Dairyland Power					10,785,013		10,785,013
2	East River Electric	OS				285,750		285,750
3	Great River Energy					29,021,151		29,021,151
4	McLeod	OS				25,606		25,606
5	Mid-Continent Area	NF				19,714		19,714
6	Midwest Ind Sys Operat		1,524,352	1,524,352		21,797,085		21,797,085
7	Minnkota Power	OS				22,890		22,890
8	New England Ind Sys Op	NF				148		148
9	NW Wisconsin Electric	OS				36,564		36,564
10	PJM Interconnection	NF				679,979		679,979
11	Redwood	OS				14,517		14,517
12	Southern Municipal					8,970,991		8,970,991
13	Stearns	OS				3,346		3,346
14	WAPA					7,109,098		7,109,098
15	Xcel Energy	OS						
16								
	TOTAL		1,524,352	1,524,352		78,771,852		78,771,852

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

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

Statistical Class: FN, OS

Schedule Page: 332 Line No.: 3 Column: b

Statistical Class: LFP, NF

Schedule Page: 332 Line No.: 6 Column: b

Statistical Class: NF, SFP, LFP, FNS

Schedule Page: 332 Line No.: 12 Column: b

Statistical Class: LFP, NF

Schedule Page: 332 Line No.: 14 Column: b

Statistical Class: LFP, FNS

Schedule Page: 332 Line No.: 15 Column: a

Xcel Energy (Interdepartmental Wheeling)

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,517,961
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	
6	Service company allocation of shareholder meeting	511,756
7	Service company allocation of director fees and ex	766,875
8	Service company allocation of SEC filing expense	114,430
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
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37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	2,911,022

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

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).

2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.

3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			3,626,162		3,626,162
2	Steam Production Plant	61,346,915	-7,758,946		-1,113,488	52,474,481
3	Nuclear Production Plant	36,140,430	-33,250,706	1,374,654		4,264,378
4	Hydraulic Production Plant-Conventional	211,391				211,391
5	Hydraulic Production Plant-Pumped Storage			106,828		106,828
6	Other Production Plant	42,980,040	294,696	86,684	-1,801,877	41,559,543
7	Transmission Plant	41,255,080			-266,771	40,988,309
8	Distribution Plant	87,808,212	1,080			87,809,292
9	Regional Transmission and Market Operation					
10	General Plant	9,576,890				9,576,890
11	Common Plant-Electric	10,557,905	-107,443	17,971,704		28,422,166
12	TOTAL	289,876,863	-40,821,319	23,166,032	-3,182,136	269,039,440

B. Basis for Amortization Charges

Account 404
Column (d) Line 1 and Line 11: Computer software is amortized over its expected useful life of 3, 5, 7 and 10 years.

Account 405
Column (e) Prefunded AFUDC recorded as a Regulatory Liability is amortized over the life of the property, and thus appears as a credit to expense.

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	311	300,886					14.70
13	312	1,282,570					17.80
14	314	295,524					17.30
15	315	167,829					15.30
16	316	48,797					13.80
17	317	-7,038					17.00
18	SUBTOTAL	2,088,568					
19							
20							
21							
22	321	368,415					19.30
23	322	873,668					17.20
24	323	254,024					18.70
25	324	237,359					16.30
26	325	123,439					18.00
27	326	-286,693					17.90
28	SUBTOTAL	1,570,212					
29							
30							
31							
32	331	544					25.20
33	332	6,794					25.20
34	333	1,727					25.20
35	334	364					25.20
36	335	61					25.20
37	SUBTOTAL	9,490					
38							
39							
40							
41	341	97,105					26.60
42	342	45,067					26.20
43	344	889,510					24.20
44	345	96,255					26.00
45	346	13,035					22.50
46	SUBTOTAL	1,140,972					
47							
48							
49							
50							

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	352	36,406	45.00		2.22	S1	
13	353	694,916	38.00		2.63	SC	
14	354	109,527	50.00	-25.00	2.50	R4	
15	355	469,443	45.00	-10.00	2.44	R1.5	
16	356	265,074	42.00	-30.00	3.10	L1	
17	357	8,371	55.00		1.82	L1.5	
18	358	14,320	40.00		2.50	L1	
19	SUBTOTAL	1,598,057					
20							
21							
22							
23	361	29,807	45.00	-30.00	2.89	R1	
24	362	429,024	38.00	-10.00	2.89	R1	
25	364	279,049	40.00	-90.00	4.75	R1.5	
26	365	327,258	35.00	-30.00	3.71	R1	
27	366	182,002	50.00		2.00	R3	
28	367	832,538	35.00	20.00	2.29	R2.5	
29	368	332,095	32.00	10.00	2.81		
30	368	17,945	25.00		4.00		
31	369	75,041	40.00	-35.00	3.38	R2.5	
32	369	184,206	40.00	-35.00	3.38	R2.5	
33	370	105,470	15.00		6.67		
34	371	19,791					
35	371	1,635					
36	371	1,280					
37	373	49,176	25.00	-20.00	4.80	L5	
38	374	85					
39	SUBTOTAL	2,866,402					
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	390	56,135	45.00		2.22	R1	
13	391	22,358	18.00	5.00	5.28		
14	391	14,237	4.00		25.00		
15	392*		10.00	10.00	9.00		
16	392*		10.00	10.00	9.00		
17	392*		12.00	5.00	7.92		
18	393	2,250	20.00		5.00		
19	394	36,851	15.00		6.67		
20	394		5.00		20.00		
21	395	4,556	10.00		10.00		
22	396*		10.00	10.00	9.00		
23	397	19,125	15.00		6.67		
24	398	2,754	15.00		6.67		
25	SUBTOTAL	158,266					
26							
27	TOTAL	9,431,967					
28							
29	* See Footnote						
30							
31							
32							
33							
34							
35							
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50							

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
FOOTNOTE DATA			

Schedule Page: 336 Line No.: 17 Column: a

317 Steam Production - Asset Retirement Costs

Schedule Page: 336 Line No.: 22 Column: a

321 Nuclear - Structures and Improvements

Schedule Page: 336 Line No.: 23 Column: a

322 Nuclear - Reactor Plant Equipment

Schedule Page: 336 Line No.: 24 Column: a

323 Nuclear - Turbogenerators

Schedule Page: 336 Line No.: 25 Column: a

324 Nuclear - Accessory Electric Equipment

Schedule Page: 336 Line No.: 26 Column: a

325 Nuclear - Miscellaneous Plant Equipment

Schedule Page: 336 Line No.: 27 Column: a

326 Nuclear - Asset Retirement Costs

Schedule Page: 336.1 Line No.: 29 Column: a

368 Line Transformers

Schedule Page: 336.1 Line No.: 30 Column: a

368 Line Capacitors

Schedule Page: 336.1 Line No.: 31 Column: a

369 Overhead Services

Schedule Page: 336.1 Line No.: 32 Column: a

369 Underground Services

Schedule Page: 336.1 Line No.: 34 Column: a

371 Leased Property on Customers' Premises

Schedule Page: 336.1 Line No.: 35 Column: a

371 Leased Property on Customers' Premises

Schedule Page: 336.1 Line No.: 36 Column: a

371 Leased Property on Customers' Premises

Schedule Page: 336.1 Line No.: 37 Column: a

373 Street Lighting and Signal Systems

Schedule Page: 336.2 Line No.: 12 Column: a

390 Structures and Improvements

Schedule Page: 336.2 Line No.: 13 Column: a

391 Office Furniture and Equipment

Schedule Page: 336.2 Line No.: 14 Column: a

391 Network Equipment

Schedule Page: 336.2 Line No.: 19 Column: a

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

394 Other Tools and Work Equipment

Schedule Page: 336.2 Line No.: 20 Column: a

394 Hand Held Meter Reading Devices

Schedule Page: 336.2 Line No.: 23 Column: a

397 Communication and Telecommunication Equipment

Schedule Page: 336.2 Line No.: 29 Column: a

392/396 Separate Provision is charged to clearing accounts monthly, computed as described below in footnote (1)

	Charged To Clearing Accts	Depreciable Plant Base
	-----	-----
392 Cars, Vans and Light Trucks	1,218,072	13,885,482
392 Licensed Trailers	166,250	2,263,711
392 Heavy Trucks	1,827,140	23,226,931
396 Trenchers, Loaders, Cranes and Other Power Operated Equipment	345,118	5,535,914
	-----	-----
Total	3,556,580	44,912,038

Footnotes: Section C

- (1) Column (b) Computation
Depreciable Plant Balances are an average of the beginning and ending plant balances for the year. Column (b) Functional Classification Totals exclude Separate Provision.
- (2) Column (c) through (g)
Subaccounts 311-346: A remaining life technique is applied to each generating facility. Therefore, column (g) represents dollar weighted composites at the plant subaccount level and column (c), (d), (e) and (f) do not apply. Changes requested from the MPUC in 2007 were approved in 2007.
- (3) P337 Line 22-26(d) - Effective Aug 1, 1981, Nuclear Plant Decommissioning

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	Expenses incurred preparing filings and				
2	attending conferences and hearings				
3					
4	Minnesota				
5	Docket Nos.				
6	E-002/RP-00-787 (2002 Resource Plan)	3,836		3,836	
7					
8					
9	Mandated Customer Bill Inserts		162,751	162,751	
10					
11					
12					
13	Assessments by the State of Minnesota,				
14	Minnesota Public Service Commission and the				
15	Department of Public Service for rate and				
16	other expenses in accordance with provision	2,420,669		2,420,669	
17	of the 1974 utility regulation law.	609,955		609,955	
18					
19	State of South Dakota Public Utilities				
20	Commission special hearing fund assessment	267,718		267,718	
21					
22	State of North Dakota Public Utilities	78,156		78,156	
23	Commission special hearing fund assessment	1,538		1,538	
24	Minnesota Office of Pipeline Safety	101,974		101,974	
25					
26	NERC Fees	1,492,195		1,492,195	
27	FERC Annual Assessment		23,208	23,208	
28	FERC Annual Assessment	4,302		4,302	
29					
30	Expenses of state rate case filings:				
31	Retail electric				
32	Retail gas				
33					
34	Various Miscellaneous Regulatory Expenses				
35	Electric	71,429	126	71,555	
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	5,051,772	186,085	5,237,857	

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR			AMORTIZED DURING YEAR				
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
							2
							3
							4
							5
Electric	E928	3,836					6
							7
							8
Electric	E928	162,751					9
							10
							11
							12
							13
							14
							15
Electric	E928	2,420,669					16
Gas	G928	609,955					17
							18
							19
Electric	E928	267,718					20
							21
Electric	E928	78,156		165	-107,143		22
Gas	G928	1,538					23
Gas	G928	101,974					24
							25
Electric	E928	1,492,195		165	1,460,057		26
Electric	E928	23,208					27
Gas	G928	4,302					28
							29
							30
Electric	E928	945,287		186,254	945,287		31
Gas	G928	460,230		186	460,230		32
							33
							34
Electric	E928	71,555					35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		6,643,374			2,758,431		46

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 350 Line No.: 1 Column: a

	2002 resource plan	Mandated customer bill inserts	Minnesota assessment	South Dakota assessment	North Dakota assessment
Total expense	\$ 3,836	\$ 162,751	\$3,030,624	\$267,718	\$ 79,694
E928	\$ 3,836	\$ 162,751	\$2,420,669	\$267,718	\$ 78,156
G928			609,955		1,538
	\$ 3,836	\$ 162,751	\$3,030,624	\$267,718	\$ 79,694
Current period transactions	\$ 3,836	162,751	3,030,624	267,718	186,837
Amortized from Acct No. 165					(107,143)
Amortized from Acct No. 186					
Amortized from Acct No. 254					
	\$ 3,836	\$ 162,751	\$3,030,624	\$267,718	\$ 79,694
					a
	Minnesota Office of Pipeline Safety	NERC fees	FERC assessment	Miscellaneous electric	
Total expense	\$101,974	\$1,492,195	\$ 27,510	\$ 71,555	
E928		\$1,492,195	\$ 23,208	\$ 71,555	
G928	101,974		4,302		
	\$101,974	\$1,492,195	\$ 27,510	\$ 71,555	
Current period transactions	101,974	32,138	27,510	71,555	
Amortized from Acct No. 165		1,460,057			
Amortized from Acct No. 186					
Amortized from Acct No. 254					
	\$101,974	\$1,492,195	\$ 27,510	\$ 71,555	
	State Rate Cases	North Dakota electric	Minnesota gas	North Dakota gas	
Total expense	\$807,385	\$ 137,902	\$ 410,230	\$ 50,000	
E928	\$807,385	\$ 137,902			
G928			410,230	50,000	
	\$807,385	\$ 137,902	\$ 410,230	\$ 50,000	
Current period transactions					
Amortized from Acct No. 165					
Amortized from Acct No. 186	799,096	100,000	396,920	50,000	
Other from Acct No. 186 (b)		37,902	13,310		
Amortized from Acct No. 254	8,289				
	\$807,385	\$ 137,902	\$ 410,230	\$ 50,000	

a) includes reclasses of (\$250,000) back to Account No. 165.

b) adjustments to reduce the accumulated balance to the amount authorized in the rate order.

Schedule Page: 350 Line No.: 31 Column: a

Amortization period per instruction 3:

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Minnesota electric retail rate case: Amortized over 48 months ending December 2012.

North Dakota electric retail rate case: Amortized over 36 months ending December 2010.

See page 233.

Schedule Page: 350 Line No.: 31 Column: e

Balance of \$1,094,343 is deferred in Account No. 186 Miscellaneous Deferred Debits. See page 233.

Schedule Page: 350 Line No.: 31 Column: i

Balance of \$1,382,129 is deferred in Account No. 186 Miscellaneous Deferred Debits. See page 233.

Schedule Page: 350 Line No.: 32 Column: a

Amortization period per instruction 3:

Minnesota gas retail rate case: Amortized over 36 months ending December 2012.

North Dakota gas retail rate case: Amortized over 36 months ending December 2010.

See page 233.

Schedule Page: 350 Line No.: 32 Column: e

Balance of \$515,727 is deferred in Account No. 186 Miscellaneous Deferred Debits. See page 233.

Schedule Page: 350 Line No.: 32 Column: i

Balance of \$362,761 is deferred in Account No. 186 Miscellaneous Deferred Debits. See page 233.

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

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

Line No.	Classification (a)	Description (b)
1	B(1)	Fees
2		Lark-Tripp user group
3		Green Circuits and 172B
4		
5	B2	Fees
6		Other
7		
8	B4	American Gas Association
9		American Wind Energy Association
10		Cambridge Energy Research Associates Inc.
11		Carbon Sequestration Council
12		Center for Energy and Environment
13		Colorado School of Mines
14		Consortium for Energy Efficiency
15		Emerging Energy Research
16		Energy Insights
17		Environmental Systems Research Institute
18		Lighting Research Center
19		Midwest Research Institute
20		Mountain States Hydrogen Business Council
21		National Hydrogen Association
22		National Renewable Energy Laboratory
23		North American Transmission Forum
24		Nvision Research
25		Renewable Development Fund program
26		SAM Research AG
27		Sundel Research Inc.
28		University of Minnesota
29		University of North Dakota
30		
31		
32		
33		
34		
35		
36		
37		
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

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

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

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
	2,288,394	see note	2,288,394		1
	5,140	e921	5,140		2
	14,465	e580	14,465		3
					4
	562,114	see note	562,114		5
	5,808	c921	5,808		6
					7
	131,766	g930.2	131,766		8
	19,285	e930.2	19,285		9
	50,000	e506	50,000		10
	9,120	e930.2	9,120		11
	10,565,884	see note	10,565,884		12
	56,490	e182.3	56,490		13
	58,511	see note	58,511		14
	7,595	c921	7,595		15
	11,658	see note	11,658		16
	3,050	see note	3,050		17
	30,000	e182.3	30,000		18
	376,900	n426.1	376,900		19
	107	c930.2	107		20
	4,236	c921	4,236		21
	3,851	c930.1	3,851		22
	14,484	e930.2	14,484		23
	53,045	c921	53,045		24
	10,779,184	e182.3	10,779,184		25
	7,012	c923	7,012		26
	489	c921	489		27
	814,409	see note	814,409		28
	7,000	see note	7,000		29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		/ /	2009/Q4
FOOTNOTE DATA			

Schedule Page: 352 Line No.: 1 Column: e

e517	\$ 2,104,045
e923	32,645
e930.2	151,704
	<u>\$ 2,288,394</u>

Schedule Page: 352 Line No.: 5 Column: e

e930.2	\$ 457,436
n426.4	91,400
n426.1	13,278
	<u>\$ 562,114</u>

Schedule Page: 352 Line No.: 12 Column: e

e182.3	\$ 10,549,513
g182.3	16,371
	<u>\$ 10,565,884</u>

Schedule Page: 352 Line No.: 14 Column: e

e182.3	\$ 48,766
g182.3	9,745
	<u>\$ 58,511</u>

Schedule Page: 352 Line No.: 16 Column: e

c930.2	\$ 10,935
c908	723
	<u>\$ 11,658</u>

Schedule Page: 352 Line No.: 17 Column: e

c921	\$ 1,257
e561.2	1,000
e588	428
g880	365
	<u>\$ 3,050</u>

Schedule Page: 352 Line No.: 25 Column: b

The "Renewable Development Fund" is a program authorized by Minnesota Statute 116C.779. Funding through this statute supports energy production and research and development of alternative sources of electricity. The projects listed below support the research and development of renewable sources of electricity. Also see page 269 "Other Deferred Credits" (Account No. 253).

RDF class B and C research projects

Xcel Energy Battery	\$ 740,027
University of Florida	579,718
Bepex International	337,585
Interphases Research	285,000
University of North Dakota (digester)	267,542
University of Minnesota (biomass)	185,713
Production Specialties	182,988
University of North Dakota (turbine)	180,031
University of Minnesota (nanocrystals)	170,044
Energy Performance Systems	167,452
University of North Dakota (liquefaction)	133,991
SarTac Corp.	130,000
West Central Telephone Association	123,300
Global Energy Concepts	120,000

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report
Northern States Power Company (Minnesota)		/ /	2009/Q4
FOOTNOTE DATA			

Coaltec Energy USA	100,000
University of Minnesota (cropping)	57,942
Colorado School of Mines (fuel cells)	56,490
University of Minnesota (Koda)	49,828
North Plains Power	45,000
National Renewable Energy Laboratory (solar cell)	(9,871)
National Renewable Energy Laboratory (low band gap solar)	(55,548)
National Renewable Energy Laboratory (inkjet solar)	(55,548)
	<u>\$ 3,791,684</u>

RDFd legislative mandate research projects	
Minnesota Department of Commerce Next Gen	\$ 4,487,500
University of Minnesota IREE	2,500,000
	<u>\$ 6,987,500</u>
	<u>\$ 10,779,184</u>

Schedule Page: 352 Line No.: 28 Column: e
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e182.3	\$ 553,715
n426.1	100,000
g182.3	84,940
c908	75,754
	<u>\$ 814,409</u>

Schedule Page: 352 Line No.: 29 Column: e
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n426.4	\$ 5,000
n426.1	2,000
	<u>\$ 7,000</u>

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	4,405,427		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	4,841,895		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	617,616		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,	38,257		
54	Other Gas Supply (Enter Total of lines 33 and 45)	403,958		
55	Storage, LNG Terminating and Processing (Total of lines 31 thru	1,119,528		
56	Transmission (Lines 35 and 47)	162,231		
57	Distribution (Lines 36 and 48)	18,065,701		
58	Customer Accounts (Line 37)	3,737,854		
59	Customer Service and Informational (Line 38)	1,073,645		
60	Sales (Line 39)	20,607		
61	Administrative and General (Lines 40 and 49)	5,747,038		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	30,986,435	935,790	31,922,225
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	409,458,226	12,365,629	421,823,855
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	94,689,952	2,859,634	97,549,586
69	Gas Plant	9,804,231	296,088	10,100,319
70	Other (provide details in footnote):	66,012	1,994	68,006
71	TOTAL Construction (Total of lines 68 thru 70)	104,560,195	3,157,716	107,717,911
72	Plant Removal (By Utility Departments)			
73	Electric Plant	7,172,855	216,620	7,389,475
74	Gas Plant	339,620	10,257	349,877
75	Other (provide details in footnote):	37,060	1,119	38,179
76	TOTAL Plant Removal (Total of lines 73 thru 75)	7,549,535	227,996	7,777,531
77	Other Accounts (Specify, provide details in footnote):			
78	Miscellaneous Deferred Debits (Acct. No. 186)	5,398	163	5,561
79	Regulatory Assets (Acct No. 182.3)	5,878,448	177,529	6,055,977
80	Regulatory Liabilities (Acct No. 254)	119,976	3,623	123,599
81	Nonutility (Accts No. 415-21)	665,470	20,097	685,567
82	Miscellaneous Income and Deductions (Accts No. 426.1-5)	565,828	17,088	582,916
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	7,235,120	218,500	7,453,620
96	TOTAL SALARIES AND WAGES	528,803,076	15,969,841	544,772,917

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr)	
Northern States Power Company (Minnesota)		/ /	2009/Q4
FOOTNOTE DATA			

Schedule Page: 354 Line No.: 70 Column: b

Nonutility CWIP

Schedule Page: 354 Line No.: 75 Column: b

Nonutility RWIP

20100428-8067 FERC PDF (Unofficial) This Report is: 04/16/2010	Date of Report (Mo, Da, Yr)	Year/Period of Report
Name of Respondent Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	End of <u>2009/Q4</u>

COMMON UTILITY PLANT AND EXPENSES

- 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.
- 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.
- 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.
- 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.

1,2,3 - see below

Account	Allocated to		Cost at Dec.31, 2009
	Electric	Gas	
COMMON UTILITY PLANT IN SERVICE AND COMPLETED NOT CLASSIFIED			
301 Organization	\$ 82,941	\$ 17,667	\$ 100,608
303 Computer software	216,857,517	46,191,388	263,048,905
Total intangible plant	\$ 216,940,458	\$ 46,209,055	\$263,149,513
389 Land and land rights	\$ 3,774,166	\$ 360,547	\$ 4,134,713
390 Structures and improvements	91,632,630	8,753,687	100,386,317
391 Office furniture and equipment	69,792,799	6,667,323	76,460,122
392 Transportation equipment	7,627,348	1,302,162	8,929,510
393 Stores equipment	380,718	36,370	417,088
394 Tools/shop/garage equipment	1,632,085	155,344	1,787,429
395 Laboratory equipment	46,306	4,424	50,730
396 Power operated equipment	26,047	3,159	29,206
397 Communications equipment	9,206,055	879,457	10,085,512
398 Miscellaneous equipment	821,262	78,455	899,717
399.1 Asset retirement costs for general plant	(1,669,813)	(159,518)	(1,829,331)
	\$ 400,210,061	\$ 64,290,465	\$464,500,526
COMMON UTILITY PLANT HELD FOR FUTURE USE			
389 Land and land rights	\$ -	\$ -	\$ -
COMMON UTILITY PLANT CONSTRUCTION WORK IN PROGRESS			
General plant	\$ 19,406,061	\$ 3,129,611	\$ 22,535,672
COMMON UTILITY PLANT ACCUMULATED PROVISION FOR DEPRECIATION			
General plant	\$ 242,366,779	\$ 43,154,189	\$285,520,968

20100428-8067 FERC PDF (Unofficial) This Report is 04/16/2010	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	End of 2009/Q4

COMMON UTILITY PLANT AND EXPENSES

- 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.
- 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.
- 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.
- 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.

Common utility plant and accumulated provision for depreciation has been allocated to the various utilities on the basis of customers, employee labor, or direct assignment based on actual use.

DEPARTMENTAL ALLOCATION OF ACCUMULATED PROVISION FOR DEPRECIATION

	"Non-Legal" ARO Balances
Common General	\$ (5,002,996)
Common Intangible	-
Total Common	\$ (5,002,996)

###

COMMON UTILITY PLANT EXPENSES

	Electric	Gas	Total
403 Depreciation Expense	\$ 10,557,905.26	\$ 989,603.43	\$ 11,547,508.69
403.1 Depreciation Expense for ARC	(107,443.43)	(10,045.28)	(117,488.71)
404 Amortization of Limited Term Electric Plant	17,971,705.28	3,855,043.65	21,826,748.93
407.4 Amortization of Regulatory Credits	53,340.86	5,121.04	58,461.90
408.1 Taxes Other than Income Tax - Utility	5,475,311.32	505,812.18	5,981,123.51
410.1 Provision for Deferred Income Taxes	284,907.70	27,217.30	312,125.00
411.1 Provision for Deferred Income Taxes - Credit	(1,132,488.58)	(106,883.42)	(1,239,372.00)
411.9 Accretion Expense	53,902.83	5,123.98	59,026.81
901 Customer Accounts Supervision	252,547.10	61,761.00	314,308.10
902 Meter Reading	19,518,644.10	4,773,202.20	24,291,846.30
903 Customer Records and Collections	25,887,058.83	6,330,777.80	32,217,836.62
904 Uncollectible Accounts	477,291.14	116,628.51	593,919.65
905 Miscellaneous Customer Accounts	89,342.31	21,851.61	111,193.92
908 Customer Assistance	3,281,735.75	802,545.98	4,084,281.67
909 Informational and Instructional	1,187,857.19	290,506.20	1,478,363.39
912 Demonstrating and Selling	94,587.93	23,130.72	117,718.63
920 Administrative and General Salaries	43,229,139.40	4,107,733.19	47,336,872.46
921 Office Supplies and Expenses	36,274,373.98	3,447,320.33	39,721,694.71
922 Administrative Expense Transferred	(12,072,631.99)	(1,147,195.81)	(13,219,827.80)
923 Outside Services	8,918,573.23	847,884.20	9,766,457.43
924 Property Insurance	3,943,471.43	374,912.25	4,318,383.68
925 Injuries and Damages	8,289,867.75	745,606.33	9,035,474.05
926 Employee Pension and Benefits	11,988,621.13	1,066,371.15	13,054,992.23
928 Regulatory Commission	5,727.18	538.31	6,265.49

COMMON UTILITY PLANT AND EXPENSES

- 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.
- 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.
- 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.
- 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.

930.1	General Advertising	2,851,583.61	270,750.99	3,122,334.60
930.2	Miscellaneous General	1,441,262.62	137,283.37	1,578,545.99
931	Rents	11,082,367.79	1,053,420.44	12,135,788.23
935	Maintenance of General Plant	443,254.54	42,091.95	485,346.48
		-----	-----	-----
		\$200,341,816.26	\$28,638,113.60	\$228,979,929.96

Basis of allocation of Common Utility Plant expenses:

From	Through	Allocation Methods
----	-----	-----
403	403	Depreciation allocator (excluding integrated software)
404	404	Software amortization allocator
408	408	(property tax portion) Depreciation allocator (excluding integrated software)
408	408	(payroll tax portion) Labor
408	408	(taxes other than income portion) 3-factor (operating revenue, plant in service, supervised O&M).
411.1	411.9	3-factor (operating revenue, plant in service, supervised O&M)
427	431	Net plant
432	432	AFUDC allocator
901	917	Customer bill ratio from end of year 2008. Used for customer account, customer information and sales.
920	924	2008 actuals -- 3-factor -- operating revenue, utility plant in service, supervised O&M used for all A&G except 925 and 926.
925	926	2008 actuals - operating labor - used for 925 and 926.
927	935	2008 actuals -- 3-factor -- operating revenue, utility plant in service, supervised O&M used for all A&G except 925 and 926.

Common Utility Plant and Accumulated Provision for Depreciation. The Form 1 reports common utility plant and accumulated provision for depreciation allocated to the electric department at the end of the year. The Company uses a 13-month average calculation for the electric department common utility plant and accumulated provision for depreciation in the formula.

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)	55,816,244	90,262,081	150,079,611	228,917,125
3	Net Sales (Account 447)	37,440,522	63,305,315	96,617,443	129,287,413
4	Transmission Rights	12,635	90,318	198,182	93,585
5	Ancillary Services	728,232	858,351	1,014,562	1,456,230
6	Other Items (list separately)				
7	Administration Fees	2,443,110	4,983,699	8,605,817	11,405,807
8					
9					
10					
11					
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40					
41					
42					
43					
44					
45					
46	TOTAL	96,440,743	159,499,764	256,515,615	371,160,160

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	1,594,796	MW	453,596			1,069,665
2	Reactive Supply and Voltage	1,594,796	MW	9,377,380			9,266,886
3	Regulation and Frequency Response	1,594,793	MW	401,925			9,635
4	Energy Imbalance			743,613			
5	Operating Reserve - Spinning			172,914			7,506
6	Operating Reserve - Supplement			143,994			1,346
7	Other	1,594,796	MW	10,318,958			
8	Total (Lines 1 thru 7)	6,379,181		21,612,380			10,355,038

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 398 Line No.: 4 Column: b

Volume of units is not available.

Schedule Page: 398 Line No.: 5 Column: b

Volume of units is not available.

Schedule Page: 398 Line No.: 6 Column: b

Volume of units is not available.

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

Administration Charge	\$ 88
Application Charge	200
Schedule 10 ISO Recovery Adder	9,880,114
Schedule 11 Wholesale Distribution Service	231,688
Ancillary Services	186,200
Service Charge	20,668
Total Other Charges	\$10,318,958

Schedule Page: 398 Line No.: 8 Column: b

Number of units is the same for all ancillary service types.

Schedule Page: 398 Line No.: 8 Column: e

Volume of units is not available.

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: Northern State Power Co. Integrated 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	7,652	14	1900	6,544	669	144			
2	February	7,322	2	1900	6,255	646	144			
3	March	6,863	11	1200	5,899	607	144			
4	Total for Quarter 1	21,837			18,698	1,922	432			
5	April	6,352	1	1100	5,462	547	144			
6	May	7,796	20	1700	6,676	592	644			
7	June	9,597	23	1400	8,115	772	644			
8	Total for Quarter 2	23,745			20,253	1,911	1,432			
9	July	8,369	10	1600	7,094	484	644			
10	August	9,123	14	1700	7,786	739	644			
11	September	7,851	10	1600	6,780	633	644			
12	Total for Quarter 3	25,343			21,660	1,856	1,932			
13	October	6,475	21	1300	5,600	538	644			
14	November	6,920	30	1800	5,878	581	644			
15	December	7,738	15	1800	6,614	650	644			
16	Total for Quarter 4	21,133			18,092	1,769	1,932			
17	Total Year to Date/Year	92,058			78,703	7,458	5,728			

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

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

The Northern States Power Co. Integrated System refers to the interconnected production and transmission facilities of both Northern States Power Co. (a Minnesota corporation) which has customers in Minnesota, North Dakota and South Dakota, and Northern States Power Co. (a Wisconsin corporation) which has customers in Michigan and Wisconsin (collectively, the "NSP Companies"). The construction, operation and maintenance of the two companies' systems is coordinated.

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

19:00 CST

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

Firm Network Service - For Self includes load in the Otter Tail Power Balancing Authority (OTP BA). The NSP Companies' load in the OTP BA at the OTP coincident peak is:

(a)	(e)
January	313
February	322
March	307
April	267
May	267
June	316
July	287
August	287
September	291
October	247
November	243
December	326
Total	<u>3,473</u>

Firm Network Service - For Self does not include the NSP Companies' load on transmission assets in the Great River Energy Balancing Authority (GRE BA). The NSP Companies' load in the GRE BA at the Great River Energy coincident peak is:

(a)	
January	68
February	63
March	63
April	52
May	52
June	74
July	57
August	65
September	75
October	50
November	59
December	65
Total	<u>743</u>

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

Firm Network Service - For Others does not include the load of Great River Energy (GRE) or Southern Minnesota Municipal Power Agency (SMMPA) in the NSP Companies' Midwest ISO Pricing Zone. The GRE and SMMPA network load not included in column (f) is:

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

(a)

	GRE	SMMPA
January	700	122
February	661	119
March	576	111
April	511	107
May	678	114
June	843	149
July	774	124
August	780	132
September	659	119
October	490	110
November	638	110
December	701	126
Total	8,011	1,443

Schedule Page: 400 Line No.: 2 Column: d

19:00 CST

Schedule Page: 400 Line No.: 3 Column: d

12:00 CDT

Schedule Page: 400 Line No.: 5 Column: d

11:00 CDT

Schedule Page: 400 Line No.: 6 Column: d

17:00 CDT

Schedule Page: 400 Line No.: 7 Column: d

14:00 CDT

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

16:00 CDT

Schedule Page: 400 Line No.: 10 Column: d

17:00 CDT

Schedule Page: 400 Line No.: 11 Column: d

16:00 CDT

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

13:00 CDT

Schedule Page: 400 Line No.: 14 Column: d

18:00 CST

Schedule Page: 400 Line No.: 15 Column: d

18:00 CST

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									

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)	34,774,922
3	Steam	17,855,988	23	Requirements Sales for Resale (See instruction 4, page 311.)	7,364,202
4	Nuclear	12,393,425	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,966,760
5	Hydro-Conventional	52,217	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	37,002
7	Other	1,967,497	27	Total Energy Losses	2,717,388
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	48,860,274
9	Net Generation (Enter Total of lines 3 through 8)	32,269,127			
10	Purchases	16,546,660			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	1,898,165			
17	Delivered	1,853,678			
18	Net Transmission for Other (Line 16 minus line 17)	44,487			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	48,860,274			

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: MN-WI-SD

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	4,419,172	86,686	5,140	15	1900
30	February	3,832,196	263,299	4,891	3	1900
31	March	4,003,226	300,544	4,557	12	800
32	April	3,594,560	187,992	4,135	14	1100
33	May	3,905,130	515,855	5,343	20	1700
34	June	4,132,340	407,820	6,773	23	1400
35	July	4,530,918	585,713	5,945	10	1600
36	August	4,668,386	673,013	6,384	12	1700
37	September	3,967,315	210,778	5,503	10	1600
38	October	3,823,133	230,045	4,480	15	1100
39	November	3,667,610	212,617	4,459	19	1800
40	December	4,316,288	292,398	5,303	15	1800
41	TOTAL	48,860,274	3,966,760			

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 401 Line No.: 29 Column: Sys

The "MN-WIS-SD" system includes energy for the Minnesota and South Dakota customers of Northern States Power Co. (a Minnesota corporation) plus energy sold to Northern States Power Co. (a Wisconsin corporation) under the Interchange Agreement. See the Notes to the Financial Statements.

The information required by Instruction 1 for other portions of the system which are not physically connected follows:

Month	Energy	Month's non-requirements sales for resale and associated losses	Monthly Peak Megawatts	Day	Hour
(a)	(b)	(c)	(d)	(e)	(f)
Northern States Power Co. (Fargo-Grand Forks N.D. System)					
January	217,811		372	15	800
February	182,583		347	3	800
March	184,346		344	12	800
April	157,019		287	14	1000
May	145,085		259	20	1200
June	152,189		326	26	1500
July	158,184		317	23	1600
August	156,345		315	11	1500
September	157,993		312	17	1600
October	160,943		263	26	1000
November	157,620		278	30	1800
December	205,861		366	16	800
Total	2,035,979	-			
Northern States Power Co. (Minot N.D. System)					
January	33,205		66	26	1900
February	28,379		62	11	2000
March	29,612		64	1	2000
April	25,402		56	1	2100
May	24,862		54	13	1700
June	26,980		66	25	1800
July	29,079		70	23	1700
August	28,901		69	11	1700
September	28,731		64	19	1800
October	27,168		56	9	1200
November	26,655		57	24	2000
December	34,046		72	14	2000
Total	343,020	-			

Schedule Page: 401 Line No.: 29 Column: c

2008 billing adjustments made in 2009	(88,128)
January 2009 non-requirements sales for resale	174,814
	<u>86,686</u>

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	Plant Name: <i>Black Dog 3 & 4</i> (b)	Plant Name: <i>MN Valley</i> (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	1952	1932				
4	Year Last Unit was Installed	1960	1953				
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	279.50	46.00				
6	Net Peak Demand on Plant - MW (60 minutes)	267	0				
7	Plant Hours Connected to Load	8530	0				
8	Net Continuous Plant Capability (Megawatts)	0	0				
9	When Not Limited by Condenser Water	305	0				
10	When Limited by Condenser Water	282	0				
11	Average Number of Employees	58	0				
12	Net Generation, Exclusive of Plant Use - KWh	1289576109	0				
13	Cost of Plant: Land and Land Rights	952692	20492				
14	Structures and Improvements	26812204	4105633				
15	Equipment Costs	105242801	9506211				
16	Asset Retirement Costs	-446860	-577952				
17	Total Cost	132560837	13054384				
18	Cost per KW of Installed Capacity (line 17/5) Including	474.2785	283.7910				
19	Production Expenses: Oper, Supv, & Engr	845652	0				
20	Fuel	24010441	0				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	2757069	14366				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	830118	0				
26	Misc Steam (or Nuclear) Power Expenses	2932250	14933				
27	Rents	535172	3534				
28	Allowances	0	0				
29	Maintenance Supervision and Engineering	122135	0				
30	Maintenance of Structures	688374	154782				
31	Maintenance of Boiler (or reactor) Plant	6302714	0				
32	Maintenance of Electric Plant	1272017	16170				
33	Maintenance of Misc Steam (or Nuclear) Plant	1530050	2212				
34	Total Production Expenses	41825992	205997				
35	Expenses per Net KWh	0.0324	0.0000				
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Gas	Oil	Coal	Gas	Oil
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	MCF	Barrels	Tons	MCF	Barrels
38	Quantity (Units) of Fuel Burned	800738	70762	47	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8754	1010	139192	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	26.971	5.593	112.301	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	30.142	5.593	112.301	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.722	5.535	19.210	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.020	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	10926.400	0.000	0.000	0.000	0.000

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

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

Line No.	Item (a)	Plant Name: <i>West Faribault</i> (b)	Plant Name: <i>A S King</i> (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas Turbine	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Ind Enclosures	Conventional
3	Year Originally Constructed	1965	1968
4	Year Last Unit was Installed	1965	1968
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	32.40	598.40
6	Net Peak Demand on Plant - MW (60 minutes)	0	536
7	Plant Hours Connected to Load	0	7592
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	604
10	When Limited by Condenser Water	0	510
11	Average Number of Employees	0	118
12	Net Generation, Exclusive of Plant Use - KWh	0	3450749100
13	Cost of Plant: Land and Land Rights	20554	1341413
14	Structures and Improvements	97604	31973133
15	Equipment Costs	0	576010911
16	Asset Retirement Costs	0	-390357
17	Total Cost	118158	608935100
18	Cost per KW of Installed Capacity (line 17/5) Including	3.6469	1017.6054
19	Production Expenses: Oper, Supv, & Engr	0	888242
20	Fuel	0	60343566
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	7917674
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	1309453
26	Misc Steam (or Nuclear) Power Expenses	958	2423861
27	Rents	0	771495
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	289095
30	Maintenance of Structures	0	1367463
31	Maintenance of Boiler (or reactor) Plant	0	7803680
32	Maintenance of Electric Plant	174	779558
33	Maintenance of Misc Steam (or Nuclear) Plant	763	4954123
34	Total Production Expenses	1895	88848210
35	Expenses per Net KWh	0.0000	0.0257
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Coal Gas Oil
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		Tons MCF Barrels
38	Quantity (Units) of Fuel Burned	0 0 0	1953756 41125 101
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0 0 0	8758 1022 138877
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000 0.000 0.000	28.620 7.375 68.721
41	Average Cost of Fuel per Unit Burned	0.000 0.000 0.000	30.986 7.375 68.721
42	Average Cost of Fuel Burned per Million BTU	0.000 0.000 0.000	1.769 7.216 11.782
43	Average Cost of Fuel Burned per KWh Net Gen	0.000 0.000 0.000	0.000 0.020 0.000
44	Average BTU per KWh Net Generation	0.000 0.000 0.000	0.000 9929.360 0.000

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

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

Line No.	Item (a)	Plant Name: <i>Key City</i> (b)	Plant Name: Monticello (c)			
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas Turbine	Nuclear			
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Ind Enclosures	Conventional			
3	Year Originally Constructed	1970	1971			
4	Year Last Unit was Installed	1970	1971			
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	72.00	631.20			
6	Net Peak Demand on Plant - MW (60 minutes)	44	592			
7	Plant Hours Connected to Load	13	7394			
8	Net Continuous Plant Capability (Megawatts)	61	0			
9	When Not Limited by Condenser Water	0	595			
10	When Limited by Condenser Water	0	572			
11	Average Number of Employees	0	795			
12	Net Generation, Exclusive of Plant Use - KWh	56160	4142464000			
13	Cost of Plant: Land and Land Rights	67495	782893			
14	Structures and Improvements	1002265	161907511			
15	Equipment Costs	7597648	556174620			
16	Asset Retirement Costs	0	-155272794			
17	Total Cost	8667408	563592230			
18	Cost per KW of Installed Capacity (line 17/5) Including	120.3807	892.8901			
19	Production Expenses: Oper, Supv, & Engr	31	12404082			
20	Fuel	11099	33112640			
21	Coolants and Water (Nuclear Plants Only)	0	3011884			
22	Steam Expenses	0	14391895			
23	Steam From Other Sources	0	0			
24	Steam Transferred (Cr)	0	0			
25	Electric Expenses	5367	1035535			
26	Misc Steam (or Nuclear) Power Expenses	10683	50017942			
27	Rents	0	2062205			
28	Allowances	0	0			
29	Maintenance Supervision and Engineering	111	2980045			
30	Maintenance of Structures	5010	7			
31	Maintenance of Boiler (or reactor) Plant	0	9688526			
32	Maintenance of Electric Plant	17200	2244997			
33	Maintenance of Misc Steam (or Nuclear) Plant	21921	7972540			
34	Total Production Expenses	71422	138922298			
35	Expenses per Net KWh	1.2718	0.0335			
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Gas		Nuclear	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		MCF		Grams:U235	
38	Quantity (Units) of Fuel Burned	0	4364	0	0	405435
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	1009	0	0	107135
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	2.534	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	2.534	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	2.512	0.000	0.000	0.702
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.200	0.000	0.000	0.010
44	Average BTU per KWh Net Generation	0.000	78607.140	0.000	0.000	10503.860

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

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

Line No.	Item (a)	Plant Name: <i>Black Dog 2&5</i> (b)	Plant Name: High Bridge 7,8 & 9 (c)			
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas Turbine	Gas Turbine			
2	Type of Constr (Conventional, Outdoor, Boiler, etc)					
3	Year Originally Constructed	1987	2008			
4	Year Last Unit was Installed	2002	2008			
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	300.35	644.06			
6	Net Peak Demand on Plant - MW (60 minutes)	292	582			
7	Plant Hours Connected to Load	3737	2386			
8	Net Continuous Plant Capability (Megawatts)	298	566			
9	When Not Limited by Condenser Water	0	0			
10	When Limited by Condenser Water	0	0			
11	Average Number of Employees	15	42			
12	Net Generation, Exclusive of Plant Use - KWh	453709891	708126000			
13	Cost of Plant: Land and Land Rights	0	825987			
14	Structures and Improvements	15361662	68398212			
15	Equipment Costs	105939083	306773750			
16	Asset Retirement Costs	-102965	0			
17	Total Cost	121197780	375997949			
18	Cost per KW of Installed Capacity (line 17/5) Including	403.5218	583.7934			
19	Production Expenses: Oper, Supv, & Engr	20450	702395			
20	Fuel	22785069	41902716			
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	250004	1576258			
26	Misc Steam (or Nuclear) Power Expenses	124872	1992385			
27	Rents	71179	561839			
28	Allowances	0	0			
29	Maintenance Supervision and Engineering	134	409188			
30	Maintenance of Structures	122885	827682			
31	Maintenance of Boiler (or reactor) Plant	0	0			
32	Maintenance of Electric Plant	1280953	3495588			
33	Maintenance of Misc Steam (or Nuclear) Plant	19468	83081			
34	Total Production Expenses	24675014	51551132			
35	Expenses per Net KWh	0.0544	0.0728			
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Gas		Gas	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		MCF		MCF	
38	Quantity (Units) of Fuel Burned	0	3509199	0	0	5225658
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	1011	0	0	1015
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	6.493	0.000	0.000	8.019
41	Average Cost of Fuel per Unit Burned	0.000	6.493	0.000	0.000	8.019
42	Average Cost of Fuel Burned per Million BTU	0.000	6.422	0.000	0.000	7.900
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.050	0.000	0.000	0.060
44	Average BTU per KWh Net Generation	0.000	7820.480	0.000	0.000	7490.510

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: <i>Wilmarth</i> (d)	Plant Name: <i>High Bridge 5 & 6</i> (e)	Plant Name: <i>Riverside 8</i> (f)	Line No.						
Steam	Steam	Steam	1						
Conventional	Conventional	Conventional	2						
1948	1924	1911	3						
1951	1959	1964	4						
25.00	265.00	404.10	5						
20	0	0	6						
7992	0	0	7						
0	0	0	8						
24	0	0	9						
19	0	0	10						
25	0	0	11						
94739438	0	-4713620	12						
368322	0	0	13						
5901935	0	1594705	14						
34775069	0	-308	15						
-57328	-7516534	-3219690	16						
40987998	-7516534	-1625293	17						
1639.5199	-28.3643	-4.0220	18						
163257	26	205487	19						
2184422	0	149932	20						
0	0	0	21						
1263912	75753	3655724	22						
0	0	0	23						
0	0	0	24						
243444	0	287740	25						
765752	677862	1647593	26						
273030	39319	472416	27						
0	0	0	28						
42970	187	268867	29						
240505	0	1112564	30						
2283426	21	2302052	31						
1078248	129	348645	32						
616872	7188	1339119	33						
9155838	800485	11790139	34						
0.0966	0.0000	-2.5013	35						
RDF	Gas	Wood				Coal	Gas	Oil	36
Tons	MCF	Tons				Tons	MCF	Barrels	37
175027	29841	33	0	0	0	-11340	3025	8	38
5734	1012	5497	0	0	0	8649	1009	138138	39
2.000	5.898	12.000	0.000	0.000	0.000	46.636	7.386	61.117	40
12.746	5.898	12.000	0.000	0.000	0.000	7.619	7.386	61.117	41
1.112	5.827	1.092	0.000	0.000	0.000	0.440	7.320	10.534	42
0.000	0.030	0.000	0.000	0.000	0.000	0.000	0.010	0.000	43
0.000	21507.750	0.000	0.000	0.000	0.000	0.000	40935.360	0.000	44

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: <i>Sherburne County</i> (d)			Plant Name: <i>Blue Lake</i> (e)			Plant Name: <i>Granite City</i> (f)			Line No.
	Steam			Gas Turbine			Gas Turbine		1
	Conventional			Ind Enclosures			Ind Enclosures		2
	1976			1974			1969		3
	1987			2005			1969		4
	2061.60			559.32			72.00		5
	1897			502			65		6
	8760			106			15		7
	0			490			59		8
	1840			0			0		9
	1701			0			0		10
	379			5			0		11
	12928818488			13408000			-224060		12
	5951721			141878			40240		13
	211773236			1587264			1241718		14
	978205032			91931500			7302699		15
	2002144			0			0		16
	1197932133			93660642			8584657		17
	581.0691			167.4545			119.2313		18
	3133329			1377			0		19
	257038816			2666427			32359		20
	0			0			0		21
	8385476			0			0		22
	0			0			0		23
	0			0			0		24
	2368898			191425			29952		25
	9801365			73138			13406		26
	1669342			118797			4474		27
	0			0			0		28
	1034075			13456			3824		29
	2637130			181943			11341		30
	13060880			0			0		31
	2309941			361037			65486		32
	5400181			28434			31713		33
	306839433			3636034			192555		34
	0.0237			0.2712			-0.8594		35
Coal		Oil	Gas		Oil	Gas		Oil	36
Tons		Barrels	MCF		Barrels	MCF		Barrels	37
7688871	0	21740	188958	0	4218	5480	0	84	38
8668	0	138199	1011	0	138000	1005	0	137589	39
32.335	0.000	55.461	11.870	0.000	100.397	4.886	0.000	66.502	40
33.490	0.000	55.461	11.870	0.000	100.397	4.886	0.000	66.502	41
1.932	0.000	9.555	11.743	0.000	17.322	4.861	0.000	11.508	42
0.000	0.020	0.000	0.000	0.200	0.000	0.000	-0.140	0.000	43
0.000	10319.830	0.000	0.000	16068.640	0.000	0.000	-26758.040	0.000	44

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: <i>Inver Hills</i> (d)	Plant Name: <i>Prairie Island</i> (e)	Plant Name: <i>Angus Anson</i> (f)	Line No.						
Gas Turbines	Nuclear	Gas Turbine	1						
Ind Enclosures	Conventional		2						
1972	1973	1994	3						
1972	1974	2005	4						
280.50	1186.20	414.26	5						
308	1092	302	6						
262	8760	242	7						
350	0	384	8						
0	1098	0	9						
0	1096	0	10						
10	780	10	11						
11759085	8250961000	15073949	12						
432561	377794	1179608	13						
1248689	207958937	7432379	14						
52800542	978006453	110695357	15						
355627	-289363635	-9756	16						
54837419	896979549	119297588	17						
195.4988	756.1790	287.9776	18						
26390	43092837	57	19						
1599098	58972487	1952711	20						
0	3023348	0	21						
0	21157537	0	22						
0	0	0	23						
0	0	0	24						
289702	1138388	205140	25						
215045	62927357	388683	26						
110649	2828268	124500	27						
0	0	0	28						
2855	8339920	6111	29						
188398	478270	820839	30						
0	17232795	0	31						
1058477	9730530	1547285	32						
28426	14521142	37792	33						
3519040	243442879	5083118	34						
0.2993	0.0295	0.3372	35						
	Gas	Oil		Nuclear			Gas	Oil	36
	MCF	Barrels		Grams:U235			MCF	Barrels	37
0	194386	8053	0	771567	0	0	196560	8772	38
0	1009	140275	0	113076	0	0	1005	137603	39
0.000	5.083	75.889	0.000	0.000	0.000	0.000	5.591	97.329	40
0.000	5.083	75.889	0.000	0.000	0.000	0.000	5.591	97.329	41
0.000	5.036	12.881	0.000	0.716	0.000	0.000	5.564	16.841	42
0.000	0.140	0.000	0.000	0.010	0.000	0.000	0.130	0.000	43
0.000	20719.690	0.000	0.000	10574.290	0.000	0.000	16464.910	0.000	44

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: <i>Riverside 7, 9 & 10</i> (d)	Plant Name: (e)	Plant Name: (f)	Line No.						
Gas Turbine			1						
			2						
1911			3						
2009			4						
585.90	0.00	0.00	5						
515	0	0	6						
2229	0	0	7						
478	0	0	8						
0	0	0	9						
0	0	0	10						
65	0	0	11						
470372078	0	0	12						
450132	0	0	13						
49176753	0	0	14						
277959266	0	0	15						
0	0	0	16						
327586151	0	0	17						
559.1161	0.0000	0.0000	18						
521368	0	0	19						
30895779	0	0	20						
0	0	0	21						
0	0	0	22						
0	0	0	23						
0	0	0	24						
39688	0	0	25						
470219	0	0	26						
124825	0	0	27						
0	0	0	28						
-340	0	0	29						
2239949	0	0	30						
0	0	0	31						
1595767	0	0	32						
-2626	0	0	33						
35884629	0	0	34						
0.0763	0.0000	0.0000	35						
			36						
			37						
0	3906036	0	0	0	0	0	0	0	38
0	1013	0	0	0	0	0	0	0	39
0.000	7.910	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	7.910	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	7.809	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.070	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	8411.190	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

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

In December 2003, the Minnesota Public Utilities Commission (MPUC) approved NSP-Minnesota's metropolitan emissions reduction project (MERP) proposal to convert two coal-fueled electric generating plants to natural gas and to install advanced pollution control equipment at a third coal-fired plant. These improvements are expected to significantly reduce air emissions from these facilities, while increasing the capacity at system peak by 300 MW. The first MERP project at A.S. King plant went into service in July 2007, with the remaining two projects (High Bridge and Riverside) expected to begin operations in 2008 and 2009, respectively. The cumulative investment in the MERP project is approximately \$1 billion. The MPUC approved a rate rider to recover in-service plant costs, including the financing costs during construction, beginning January 1, 2006.

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

See explanation of NSP-Minnesota's metropolitan emissions reduction project (MERP) at page 402 line 1, column (e).

Schedule Page: 402.1 Line No.: -1 Column: c

See explanation of NSP-Minnesota's metropolitan emissions reduction project (MERP) at page 402 line 1 column (e).

Schedule Page: 402.1 Line No.: -1 Column: d

Sherburne County Generating Plant Unit 3 is jointly owned by NSP-Minnesota (59 percent) and Southern Minnesota Municipal Power Agency (41 percent). See Note 5 in Notes to Financial Statements for further discussion.

Schedule Page: 402.1 Line No.: 9 Column: d

NSP-Minnesota owns 100 percent of two units of the plant, and 59% of the third unit of the plant. The total net dependable capacity, when not limited by condenser water, is 2,066 MW. The net continuous plant capability, when not limited by condenser water, of the portion of the three units owned by NSP-Minnesota was 1,840 MW.

Schedule Page: 402.1 Line No.: 10 Column: d

NSP-Minnesota owns 100 percent of two units of the plant, and 59% of the third unit of the plant. The total net dependable capacity, when limited by condenser water, is 1,883 MW. The net continuous plant capacity, when limited by condenser water, of the portion of the three units owned by NSP-Minnesota was 1,676 MW.

Schedule Page: 402.2 Line No.: -1 Column: c

Instruction 12 - Monticello Nuclear Generating Plant (p. 403.2)

- (a) Operating and maintenance costs of the Monticello Plant are expensed as incurred.
- (b) NSP-Minnesota buys and owns the fuel for this plant. The standard FERC accounting system is used to make a breakdown of the various components of fuel costs.
- (c) The Monticello Plant is a General Electric BWR-3 Nuclear Power Plant. Fuel material is UO₂ contained in zirconium alloy based cladding. The equilibrium cycle has approximately 84 metric tons of uranium metal with a nominal U-235 enrichment of 3.9 weight percent in the fresh fuel. The reactor is licensed to operate at 1,775 MWt.

Schedule Page: 402.2 Line No.: -1 Column: e

Instruction 12 - Prairie Island Nuclear Generating Plant (p. 403.2)

- (a) Operating and maintenance costs of the Prairie Island Plant are expensed as incurred.
- (b) NSP-Minnesota buys and owns the fuel for this plant. The standard FERC accounting system is used to make a breakdown of the various components of fuel costs.
- (c) The Prairie Island Plant has two identical Westinghouse 2 loop PWR Nuclear Power Plants. Fuel material is UO₂ contained in zirconium alloy based cladding. The equilibrium cycle has approximately 42 metric tons of uranium metal with a nominal U-235 enrichment of 4.95 weight percent in the fresh fuel. The reactor is licensed to operate at 1650 MWt.

Schedule Page: 402.2 Line No.: 11 Column: c

Employees consist of:

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	/ /	2009/Q4
FOOTNOTE DATA			

109 NSP-Minnesota
275 Nuclear Managment Co.
188 Contract Labor
572

Schedule Page: 402.2 Line No.: 11 Column: e

Employees consist of:

184 NSP-Minnesota
333 Nuclear Management Co.
122 contract labor
639 Total

Schedule Page: 402.3 Line No.: -1 Column: c

See explanation of NSP-Minnesota's metropolitan emissions reduction project (MERP) at page 402 line 1, column (e).

Schedule Page: 402 Line No.: 36 Column: b1

For all of NSP-Minnesota's plants using coal as a fuel source, the average heat content of fuel burned is calculated as Btu/pound.

Schedule Page: 402 Line No.: 36 Column: b2

For all of NSP-Minnesota's plants using gas as a fuel source, the average heat content of fuel burned is calculated as Btu/cubic foot.

Schedule Page: 402 Line No.: 36 Column: b3

For all of NSP-Minnesota's plants using oil as a fuel source, the average heat content of fuel burned is calculated as Btu/gallon.

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. 2056 Plant Name: Henn Is & Upper Dam (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Run of River	
2	Plant Construction type (Conventional or Outdoor)	Conventional	
3	Year Originally Constructed	1908	
4	Year Last Unit was Installed	1955	
5	Total installed cap (Gen name plate Rating in MW)	12.42	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	12	0
7	Plant Hours Connect to Load	8,760	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	12	0
10	(b) Under the Most Adverse Oper Conditions	12	0
11	Average Number of Employees	2	0
12	Net Generation, Exclusive of Plant Use - Kwh	52,216,908	0
13	Cost of Plant		
14	Land and Land Rights	1,548,707	0
15	Structures and Improvements	464,281	0
16	Reservoirs, Dams, and Waterways	5,847,982	0
17	Equipment Costs	2,789,250	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	10,650,220	0
21	Cost per KW of Installed Capacity (line 20 / 5)	857.5056	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	21	0
24	Water for Power	0	0
25	Hydraulic Expenses	501	0
26	Electric Expenses	254,721	0
27	Misc Hydraulic Power Generation Expenses	136,657	0
28	Rents	10,157	0
29	Maintenance Supervision and Engineering	610	0
30	Maintenance of Structures	34,225	0
31	Maintenance of Reservoirs, Dams, and Waterways	146,638	0
32	Maintenance of Electric Plant	68,395	0
33	Maintenance of Misc Hydraulic Plant	6,897	0
34	Total Production Expenses (total 23 thru 33)	658,822	0
35	Expenses per net KWh	0.0126	0.0000

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

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

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

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. 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 Demand 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. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
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			16
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			36
			37
			38

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	STEAM PLANT					
2						
3	Red Wing	1949	23.00	22.6	96,818,280	44,844,994
4						
5						
6	INTERNAL COMBUSTION					
7						
8	Dispersed Generation				-249,490	2,499,099
9						
10						
11						
12	HYDRO PLANTS					
13						
14	Lower Dam	1887	8.00			810,693
15						
16						
17						
18	WIND TURBINE PLANTS					
19						
20						
21	Lake Benton	1997				10,190,362
22	Grand Meadow Wind Farm	2008	100.50	100.5	295,465,000	214,001,975
23						
24						
25	SOLAR					
26						
27	Photovoltaic Units	1995				306,139
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

GENERATING PLANT STATISTICS (Small Plants) (Continued)

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

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
						2
1,949,782	2,514,612	2,436,268	3,382,299	RDF, Gas	128	3
						4
						5
						6
						7
		14,238	35,164	Oil	1,948	8
						9
						10
						11
						12
						13
101,337				Hydro		14
						15
						16
						17
						18
						19
						20
				Wind		21
2,129,373	2,799,695		124,500	Wind		22
						23
						24
						25
						26
				Solar		27
						28
						29
						30
						31
						32
						33
						34
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						38
						39
						40
						41
						42
						43
						44
						45
						46

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	/ /	2009/Q4
FOOTNOTE DATA			

Schedule Page: 410 Line No.: 1 Column: g

The Plant Cost is manually calculated (not calculated by the FERC software) - (col g = col f / col c)

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Forbes (MPC) (5702)	Manitoba Hydro Interconn	500.00	500.00	Tower	203.79		1
2	Chisago Co (5703)	MN Power Interconn	500.00	500.00	Tower	61.56		1
3	Split Rock (0953)	Lakefield Junction	345.00	345.00	Steel Pole	85.68		1
4	Brookings (0970)	White	345.00	345.00	Steel Pole	0.31		
5	Brookings (0971)	White	345.00	345.00	Steel Pole	0.43		1
6	Wilmarth (0974)	Calpine Interconnection #3	345.00	345.00	Steel Pole	0.22		1
7	King (0975)	Red Rock	345.00	345.00	Tower	18.85		1
8					2 Pole K	6.12		1
9	Parkers Lake (0976)	Prairie Island	345.00	345.00	Tower	31.29		1
10					Tower	5.93		1
11					Steel Pole	4.13		1
12					Steel Pole	0.11		1
13					Stl Pl-0976		0.11	1
14					2 Pole K	25.91		1
15	King (0977)	Terminal	345.00	345.00	Tower	19.70		1
16					Steel Pole	3.30		1
17	Monticello (0978)	Parkers Lake	345.00	345.00	Tower	16.31		1
18					2 Pole K	20.84		1
19	Prairie Island (0979)	Adams	345.00	345.00	Tower	2.42		1
20					Tower	0.87		1
21					2 Pole K	72.96		1
22	Chisago Co (0980)	Coon Creek	345.00	345.00	Tw on 0977		11.12	1
23					Stl Pl-0977		3.30	1
24					Tower	6.98		1
25					Steel Pole	4.98		1
26					Steel Pole	31.36		1
27	King (0981)	St Croix River	345.00	345.00	Tw on 0975		14.80	1
28					Tower	0.62		1
29					2 Pole K	3.84		1
30	Blue Lake (0982)	Lakefield Junction	345.00	345.00	Tower	15.54		1
31					2 Pole K	112.87		1
32	Sherburne Co (0984)	Terminal	345.00	345.00	Tower	12.24		1
33					2 Pole K	16.21		1
34					Tw on 0977		1.97	1
35					Steel Pole	15.07		1
36					TOTAL	4,443.05	365.70	79

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1					Stl Pl-0980		5.11	1
2					Tw on 0980		6.65	1
3	Sherburne Co (0985)	CU Conn	345.00	345.00	Tower	5.82		1
4					2 Pole K	20.33		1
5					Tw on 0978		7.11	1
6	Prairie Island (0986)	Red Rock	345.00	345.00	Tower	3.29		1
7					Tw on 0979		2.42	1
8					2 Pole K	20.26		1
9					Steel Pole	5.28		1
10	Prairie Island (0987)	Red Rock	345.00	345.00	Stl Pl-0986		6.48	1
11					2 Pole K	19.33		1
12					Tw on 0986		2.16	1
13					Tower	1.47		1
14					Tw on 0976		2.57	1
15	Parkers Lake (0988)	Blue Lake	345.00	345.00	Tower		11.56	1
16					Steel Pole		3.30	1
17	Blue Lake (0989)	Red Rock	345.00	345.00	Tower	7.62		1
18					Tw on 0976		19.10	1
19					Steel Pole	0.58		1
20					Stl Pl-0976		0.83	1
21					2 Pole K	3.03		1
22	Sherburne Co (0991)	Monticello	345.00	345.00	Tw on 0985		5.78	1
23	Sherburne Co (0992)	Coon Creek	345.00	345.00	Tower	0.88		1
24					2 Pole K	16.21		1
25					Stl Pl-0984		15.07	1
26					Tw on 0984		11.34	1
27	Chisago Co (0994)	King	345.00	345.00	Tw on 0977		6.61	1
28					Stl Pl-0980		31.56	1
29	Parkers Lake (0996)	CU Conn	345.00	345.00	Tw on 0978		9.64	1
30	Split Rock (0997)	WAPA (Watertwn)	345.00	345.00	Steel Pole	5.23		1
31	Split Rock (0998)	WAPA (Sioux Cty)	345.00	345.00	Steel Pole		5.23	1
32	Black Dog (0900)	WAPA	230.00	230.00	Tower	104.34		1
33					2 Pole K	3.43		1
34	Red Rock (0902)	MP Co.	230.00	230.00	2 Pole K	66.55		1
35					2 Pole K	9.77		1
36					TOTAL	4,443.05	365.70	79

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1					Tower	4.05		1
2	Audobon (0909)	Badura	230.00	230.00	2 Pole H	38.31		1
3	Maple River (0910)	Minnkota Conn	230.00	230.00	Tower	3.61		1
4	Maple River (0911)	OTP Co	230.00	230.00	Tw on 0910		3.61	1
5		Interconn	230.00	230.00	2 Pole H	4.41		1
6	Drayton (0912)	Manitoba Hydro Interconn	230.00	230.00	2 Pole H	28.69		1
7	Sheyenne (0915)	WAPA	230.00	230.00	2 Pole H	4.26		1
8	Prairie (0916)	Minnkota-Grand Forks	230.00	230.00	2 Pole H	6.64		1
9	Split Rock (0918)	Sioux Falls	230.00	230.00	Steel Poles	0.96		
10	Paynesville Trans (0919)	Willmar	230.00	230.00	Steel Poles	26.88		
11			230.00	230.00	2 Pole H	2.99		
12	Rugby (0920)	Manitoba Hydro Inter	230.00	230.00	Steel Poles	56.32		
13	Mankato (5300)	Winnebago	161.00	161.00	2 Pole H	38.86		1
14	Split Rock (5301)	Heron Lake	161.00	161.00	2 Pole H	20.05		1
15	Lakefield Jct (5304)	Fox Lake	161.00	161.00	Steel Poles	26.48		
16	Pleasant Valley (5308)	Grand Meadow						
17	Various 115.00 OH		115.00			1,382.12	117.27	
18	Various 69.00 OH		69.00			1,612.91	46.60	
19	Various 34.50 OH		34.50			72.73	13.20	
20	Various 23.00 OH		23.00			5.55	1.20	
21	Various 115.00 UG		115.00		Undergrmd	9.78		
22	Various 69.00 UG		69.00		Undergrmd	1.59		
23	Various 34.50 UG				Undergrmd	2.00		
24	Various 13.80 UG		13.80		Undergrmd			
25	Leased Line Granite City	St. Regis						
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	4,443.05	365.70	79

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
3-1192ACSR	1,723,334	63,096,463	64,819,797					1
3-1192ACSR	2,237,403	16,371,853	18,609,256	106,787	371,318	150,120	628,225	2
	1,101,182	109,685,457	110,786,639					3
		1,268,486	1,268,486					4
	13,748	933,240	946,988					5
2-795ACSR		888,655	888,655					6
2-795ACSR	401,128	2,392,629	2,793,757					7
2-795ACSR								8
2-795ACSR	2,319,556	9,408,435	11,727,991					9
2-954ACSR								10
2-795ACSR								11
2312ACSR								12
2312ACSR								13
2-954ACSR								14
2-795ACSR	2,275,376	4,033,144	6,308,520					15
2-795ACSR								16
2-954ACSR	882,197	7,536,869	8,419,066					17
2-954ACSR								18
2-954ACSR	187,240	21,806,383	21,993,623					19
2-795ACSR								20
2-795ACSR								21
2-795ACSR	5,380,476	12,978,573	18,359,049					22
2-795ACSR								23
2-795ACSR								24
2-795ACSR								25
2-954ACSR								26
2-795ACSR	24,099	877,410	901,509					27
2-795ACSR								28
2-795ACSR								29
2-795ACSR	1,333,983	22,413,345	23,747,328					30
2-795ACSR								31
2-954ACSR	667,056	8,373,714	9,040,770					32
2-954ACSR								33
2-795ACSR								34
2-795ACSR								35
	45,500,890	898,631,390	944,132,280	1,892,544	6,580,706	2,660,515	11,133,765	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2-795ACSR								1
2-795ACSR								2
2-954ACSR	17,816	7,022,631	7,040,447					3
2-954ACSR								4
2-954ACSR								5
2-795ACSR	661,692	6,824,204	7,485,896					6
2-954ACSR								7
2-795ACSR								8
2-795ACSR								9
2-795ACSR		2,421,198	2,421,198					10
2-795ACSR								11
2-795ACSR								12
2-795ACSR								13
2-954ACSR								14
2-795ACSR		478,209	478,209					15
2-795ACSR								16
2-795ACSR	353,005	3,108,909	3,461,914					17
2-795ACSR								18
2-795ACSR								19
2-795ACSR								20
2-795ACSR								21
2-954ACSR		196,978	196,978					22
2-954ACSR	472,775	3,527,595	4,000,370					23
2-954ACSR								24
2-954ACSR								25
2-954ACSR								26
2-795ACSR		1,648,291	1,648,291					27
2-954ACSR								28
2-954ACSR		564,838	564,838					29
2-954ACSR	139,860	8,455,822	8,595,682					30
2-954ACSR		670,200	670,200	333,264	1,158,817	468,499	1,960,580	31
795ACSR	437,165	7,918,952	8,356,117					32
795ACSR								33
795ACSR	437,738	3,491,029	3,928,767					34
1272ACSR								35
	45,500,890	898,631,390	944,132,280	1,892,544	6,580,706	2,660,515	11,133,765	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272ACSR								1
795ACSR	57,863	1,257,750	1,315,613					2
795ACSR	55,625	283,964	339,589					3
795ACSR	31,735	849,481	881,216					4
795ACSR								5
954ACSR	57,281	758,399	815,680					6
795ACSR	21,223	816,980	838,203					7
954ACSR	24,662	1,095,907	1,120,569					8
		605,867	605,867					9
	302,577	7,488,803	7,791,380					10
								11
954ACSR	1,288,507	12,624,412	13,912,919	146,818	510,512	206,395	863,725	12
477ACSR	112,192	912,895	1,025,087					13
477ACSR	59,271	1,536,006	1,595,277					14
	1,693,768	17,971,713	19,665,481	34,364	119,491	48,309	202,164	15
		1,398,998	1,398,998					16
	16,795,454	367,774,244	384,569,698	603,458	2,098,329	848,334	3,550,121	17
	3,933,478	121,143,000	125,076,478	667,853	2,322,239	938,858	3,928,950	18
		9,981,224	9,981,224					19
	425	443,214	443,639					20
		21,675,479	21,675,479					21
		798,244	798,244					22
								23
								24
		821,298	821,298					25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	45,500,890	898,631,390	944,132,280	1,892,544	6,580,706	2,660,515	11,133,765	36

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2009/Q4
Northern States Power Company (Minnesota)			
FOOTNOTE DATA			

Schedule Page: 422.2 Line No.: 17 Column: f

Circuit miles

Schedule Page: 422.2 Line No.: 18 Column: f

Circuit miles

Schedule Page: 422.2 Line No.: 19 Column: f

Circuit miles

Schedule Page: 422.2 Line No.: 20 Column: f

Circuit miles

Schedule Page: 422.2 Line No.: 25 Column: k

Leased Line

Lessee: International Paper Corporation (formerly St. Regis Corp)

Old Agreement: July 14, 1983

New Agreement: January 1, 2005

2005 terms: The monthly facilities charge began at \$26,148 for the line only and was subject to adjustment indexed to NSP-IBEW labor agreements, facility additions, and other provisions for renegotiation at five-year intervals. Not an associated company.

TL MN 5509-115 KV Granite City-St. Regis	10355000	10400	526,097.44
TL MN 5509-115 KV Granite City-St. Regis	10356000	10400	295,200.74
			821,298.18

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	0970 Brooking County	White	0.14	Poles	7.00	1	1
2	0970 Brooking County	White	0.17	Poles	1.00	1	1
3							
4	5545 Nobles County	Fenton	21.65	Poles	7.00	1	1
5	5545 Nobles County	Fenton	1.45	Poles	10.00	1	1
6	5545 Nobles County	Fenton	2.45	Poles	6.00	1	1
7	5545 Nobles County	Fenton	0.41	Poles	12.00	1	1
8							
9	5546 Lyon county	SW Marshall	1.29	Poles	9.00	1	1
10	5546 Lyon county	SW Marshall	1.97	Poles	9.00	1	1
11	5546 Lyon county	SW Marshall	12.25	Poles	8.00	1	1
12							
13	5547 Yankee	Brookings County	3.94	Poles	12.00	1	1
14	5547 Yankee	Brookings County	2.16	Poles	8.00	2	2
15	5547 Yankee	Brookings County	6.14	Poles	8.00	1	1
16	5547 Yankee	Brookings County	0.37	Poles	8.00	1	1
17							
18	5549 Wilmarth GRE Tap	Pohl Sub	1.50	Poles	16.00	1	1
19	5549 Wilmarth GRE Tap	Pohl Sub	0.12	Poles	25.00	1	1
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
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37							
38							
39							
40							
41							
42							
43							
44	TOTAL		56.01		146.00	16	16

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

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

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
795-2	ACSS		345		1,132,986	135,500		1,268,486	1
795-2	ACSS		345						2
									3
795-2	ACSS		115	589,800	20,472,206	4,874,407		25,936,413	4
795-2	ACSS		115						5
795-2	ACSS		115						6
795-2	ACSS		115						7
									8
795	ACSS		115	436,934	3,981,191	3,194,712		7,612,837	9
795	ACSS		115						10
795	ACSS		115						11
									12
795-2	ACSS		115		6,366,652	3,172,547		9,539,199	13
795-2	ACSS		115						14
795-2	ACSS		115						15
795-2	ACSS		115						16
									17
795	ACSS		115		698,873	232,896		931,769	18
795	ACSS		115						19
									20
									21
									22
									23
									24
									25
									26
									27
									28
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									41
									42
									43
				1,026,734	32,651,908	11,610,062		45,288,704	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	ADA SUBSTATION	Unattended Dist	69.00	24.00	4.00
2	ADAMS SUBSTATION	Unattended Tran	15.00	2.00	
3		Unattended Tran	345.00	35.00	17.00
4	AFTON SUBSTATION	Unattended Dist	115.00	36.00	21.00
5		Unattended Dist	115.00	36.00	
6	AIRLAKE SUBSTATION	Unattended Dist	115.00	14.00	
7	AIRPORT SUBSTATION	Unattended Dist	115.00	14.00	
8	ALBANY SUBSTATION	Unattended Dist	15.00	4.00	3.00
9		Unattended Dist	69.00	34.00	7.00
10	ALDRICH SUBSTATION	Unattended Dist	115.00		
11		Unattended Dist	115.00	14.00	8.00
12		Unattended Tran			
13	ALEXANDRIA SUBSTATION	Unattended Dist	35.00	3.00	
14	ALLEN S KING SUBSTATION	Unattended Tran	345.00	68.00	14.00
15		Unattended Prod	345.00	199.00	20.00
16	ALTURA SUBSTATION	Unattended Dist	69.00	14.00	
17	ANGUS ANSON PEAKING SUBSTATION	Unattended Prod	15.00		
18	ANNANDALE SUBSTATION	Unattended Dist	69.00	13.00	
19		Unattended Dist			
20	APACHE SUBSTATION	Unattended Dist	115.00	14.00	
21	ARCHER DANIELS MIDLAND	Unattended Dist	15.00	12.00	
22	ARDEN HILLS SUBSTATION	Unattended Tran	115.00	41.00	14.00
23		Unattended Tran	115.00	71.00	15.00
24		Unattended Dist			
25	ARLINGTON SUBSTATION	Unattended Dist	69.00	39.00	3.00
26	ARTESIAN SUBSTATION	Unattended Dist	35.00	12.00	
27	ATWATER SUBSTATION	Unattended Dist	69.00	14.00	
28	AVERILL SUBSTATION	Unattended Dist	69.00	24.00	4.00
29	AVON SUBSTATION	Unattended Dist	69.00	13.00	
30		Unattended Tran			
31	BALATON SUBSTATION	Unattended Dist	15.00	3.00	
32	BALTA SUBSTATION	Unattended Tran	230.00		
33	BARNES SUBSTATION	Unattended Dist	23.00	4.00	3.00
34	BASSETT CREEK SUBSTATION	Unattended Dist	115.00	14.00	8.00
35	BATTLE CREEK SUBSTATION	Unattended Dist	115.00	14.00	8.00
36	BAYTOWN SUBSTATION	Unattended Dist	115.00	14.00	8.00
37	BEAVER CREEK SUBSTATION (WEST OLIVIA)	Unattended Tran			
38	BECKER SUBSTATION	Unattended Dist	69.00	35.00	20.00
39		Unattended Dist	69.00	36.00	20.00
40	BELGRADE SUBSTATION	Unattended Dist	69.00	4.00	3.00

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	BELL FIELD SUBSTATION	Unattended Dist	15.00	2.00	
2	BELLE PLAINE SUBSTATION	Unattended Dist	69.00	14.00	
3	BENTON COUNTY SUBSTATION	Unattended Tran	230.00	118.00	14.00
4	BIRCH SUBSTATION	Unattended Dist	69.00	36.00	
5	BIRD ISLAND SUBSTATION	Unattended Dist	69.00	4.00	
6		Unattended Tran			
7	BLACK DOG SUBSTATION	Unattended Tran	230.00	115.00	
8		Unattended Prod	115.00	14.00	
9	BLACK OAK (BLO)	Unattended Tran	69.00		
10	BLOOMINGTON SUBSTATION	Unattended Dist	115.00	14.00	
11	BLUE HERON SUBSTATION	Unattended Dist	69.00	14.00	8.00
12	BLUE LAKE SUBSTATION	Unattended Dist	115.00	14.00	8.00
13		Unattended Prod	115.00	14.00	
14		Unattended Tran	345.00	118.00	14.00
15	BLUFF CREEK SUBSTATION	Unattended Dist	115.00	14.00	8.00
16	BRIDGEWATER SUBSTATION	Unattended Dist	23.00	4.00	
17		Unattended Dist	35.00	23.00	
18	BROOK SUBSTATION	Unattended Dist	35.00	4.00	
19	BROOKINGS COUNTY SUBSTATION (BOK)	Unattended Tran	345.00	115.00	34.50
20	BROOKINGS COUNTY SUBSTATION (BOK)	Unattended Tran	345.00	115.00	13.80
21	BROOKLYN PARK SUBSTATION	Unattended Dist	115.00	14.00	8.00
22	BROOTEN SUBSTATION	Unattended Dist	69.00	13.00	8.00
23	BROWNTON SUBSTATION	Unattended Dist	69.00	2.00	
24	BUFFALO LAKE SUBSTATION	Unattended Dist	69.00	4.00	
25	BUFFALO RIDGE SUBSTATION	Unattended Tran	115.00	68.00	20.00
26	BURNSIDE SUBSTATION	Unattended Dist	69.00	13.00	8.00
27		Unattended Dist	69.00	14.00	8.00
28	BUTTERFIELD SUBSTATION	Unattended Dist	69.00	4.00	
29	BYRON SUBSTATION	Unattended Tran			
30	CANISTOTA CORNER SUBSTATION	Unattended Dist	15.00		
31	CANISTOTA JUNCTION SUBSTATION	Unattended Dist	69.00	14.00	
32		Unattended Dist	23.00	13.00	
33		Unattended Tran			
34	CANISTOTA SUBSTATION	Unattended Dist	40.00	4.00	
35	CANNON FALLS SUBSTATION	Unattended Dist	69.00	13.00	
36	CANNON FALLS TRANS SUBSTATION	Unattended Dist	69.00	14.00	8.00
37		Unattended Tran	115.00	71.00	13.80
38					
39	CANOVA SUBSTATION	Unattended Dist	35.00	13.00	
40	CANTON SUBSTATION	Unattended Dist	69.00	14.00	

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	CAP SUBSTATION	Unattended Tran			
2	CARLETON COLLEGE SUBSTATION	Unattended Dist	13.00	4.00	
3	CARVER COUNTY STATION	Unattended Tran	115.00	69.00	
4	CASS COUNTY SUBSTATION	Unattended Dist	115.00	68.00	14.00
5		Unattended Dist	115.00	24.00	2.00
6	CASTLE ROCK SUBSTATION	Unattended Dist	69.00	4.00	
7	CEDAR LAKE ROAD SUBSTATION	Unattended Dist	115.00	14.00	
8	CEDARVALE SUBSTATION	Unattended Dist	115.00	14.00	
9		Unattended Dist	115.00	14.00	8.00
10	CENTERVILLE SUBSTATION	Unattended Dist	69.00	4.00	
11	CHANARAMBIE SUB	Unattended Tran	115.00	35.00	
12	CHASKA SUBSTATION	Unattended Dist			
13	CHASKA SWITCHING STATION	Unattended Tran	15.00		
14	CHEMOLITE SUBSTATION	Unattended Dist	115.00	13.00	
15		Unattended Dist	115.00	41.00	14.00
16	CHERRY CREEK SUBSTATION	Unattended Dist	115.00	14.00	
17		Unattended Dist	115.00	35.00	
18		Unattended Tran			
19	CHISAGO COUNTY SUBSTATION	Unattended Dist	115.00	36.00	21.00
20		Unattended Tran	345.00	115.00	
21		Unattended Tran	500.00	345.00	35.00
22		Unattended Tran	115.00	69.00	
23	CLARA CITY SUBSTATION	Unattended Dist	69.00	24.00	
24		Unattended Dist	69.00	13.00	
25	CLARKS GROVE SUBSTATION	Unattended Dist	69.00	13.00	8.00
26	CLIFF AVENUE SUBSTATION	Unattended Dist	69.00	14.00	
27		Unattended Dist	69.00	4.00	
28	COKATO SUBSTATION	Unattended Dist	69.00	14.00	
29	COLVILLE SUBSTATION	Unattended Tran	161.00	115.00	13.80
30	COON CREEK SUBSTATION	Unattended Tran	345.00	115.00	35.00
31		Unattended Dist	115.00	14.00	
32	COTTAGE GROVE SUBSTATION	Unattended Dist	115.00	14.00	
33	COTTONWOOD SUBSTATION	Unattended Dist	23.00	4.00	
34	CREDIT RIVER SUBSTATION	Unattended Dist	69.00	13.00	
35	CROOKED LAKE SUBSTATION	Unattended Dist	115.00		
36		Unattended Dist	115.00	14.00	8.00
37		Unattended Dist	15.00	12.00	7.00
38	CROSSROADS SUBSTATION	Unattended Dist	115.00	14.00	8.00
39		Unattended Dist	115.00	14.00	
40	CROW RIVER STATION	Unattended Tran	115.00	41.00	14.00

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	CRYSTAL FOODS SUBSTATION	Unattended Dist	69.00	14.00	
2	DANUBE SUBSTATION	Unattended Dist	69.00	4.00	
3		Unattended Dist	69.00	4.00	
4	DASSEL SUBSTATION	Unattended Dist	69.00	14.00	
5	DAYTONS BLUFF SUBSTATION	Unattended Dist	115.00	14.00	
6	DEAN LAKE SUBSTATION	Unattended Tran			
7	DEEPHAVEN SUBSTATION	Unattended Dist	69.00	14.00	
8	DELANO SUBSTATION	Unattended Dist	69.00	7.00	
9	DELL RAPIDS SUBSTATION	Unattended Dist	35.00	13.00	
10		Unattended Dist	69.00	14.00	8.00
11	DODGE CENTER SUBSTATION	Unattended Dist	69.00	14.00	8.00
12		Unattended Dist	69.00	24.00	
13		Unattended Dist	69.00	12.50	
14	DOVE PIPELINE SUBSTATION	Unattended Dist	115.00	4.00	
15	DOUGLAS COUNTY STATION	Unattended Tran	115.00	71.00	35.00
16	DUNDAS SUBSTATION	Unattended Dist	69.00	14.00	
17	EAGLE LAKE SUBSTATION	Unattended Dist	69.00	13.00	
18	EAST BLOOMINGTON SUBSTATION	Unattended Dist	115.00	14.00	
19	EAST WINONA SUBSTATION	Unattended Dist	69.00	14.00	8.00
20	EASTWOOD SUBSTATION	Unattended Dist	115.00	14.00	
21	ECHO SUBSTATION	Unattended Dist	23.00	4.00	
22	EDEN PRAIRIE SUBSTATION	Unattended Dist	115.00	14.00	8.00
23		Unattended Tran	345.00	68.00	14.00
24	EDEN VALLEY SUBSTATION	Unattended Dist	35.00	4.00	
25	EDGERTON SUBSTATION	Unattended Dist	23.00	4.00	
26		Unattended Dist	23.00	4.00	
27	EDINA SUBSTATION	Unattended Dist	115.00	14.00	
28	ELLIOT PARK SUBSTATION	Unattended Dist	115.00	14.00	
29		Unattended Dist	115.00	14.00	8.00
30		Unattended Tran			
31	ELM CREEK SUBSTATION	Unattended Dist	115.00	14.00	
32		Unattended Dist	115.00	35.00	
33		Unattended Tran	345.00	115.00	14.00
34	EMERY SUBSTATION	Unattended Dist	35.00	4.00	
35	EMPIRE PARK SUBSTATION	Unattended Dist	35.00	4.00	3.00
36	ESSIG SUBSTATION	Unattended Dist	69.00	2.00	
37	EXCELSIOR SUBSTATION	Unattended Dist	69.00	14.00	
38		Unattended Dist			
39		Unattended Tran			
40	FAIR PARK SUBSTATION	Unattended Dist	69.00	14.00	8.00

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1		Unattended Tran			
2	FARIBAULT SUBSTATION	Unattended Dist	69.00	14.00	
3		Unattended Tran			
4	FARIBAULT WATER PUMPING SUBSTATION	Unattended Dist	15.00	14.00	3.00
5	FARMINGTON SUBSTATION	Unattended Dist	69.00	14.00	8.00
6		Unattended Dist	69.00	14.00	
7	FENTON	Unattended Tran	115.00	34.50	13.80
8	FIELDON	Unattended Tran	345.00		
9	FIESTA CITY SUBSTATION	Unattended Dist	69.00	14.00	8.00
10		Unattended Tran			
11	FIFTH STREET SUBSTATION	Unattended Dist	115.00	14.00	
12	FOLEY SUBSTATION	Unattended Dist	35.00	4.00	
13	FORBES SUBSTATION	Unattended Tran	500.00	20.00	
14	FORT RIDGELY SUBSTATION	Unattended Tran	115.00	71.00	14.00
15	FRANKLIN STATION	Unattended Dist	69.00	4.00	
16		Unattended Dist	69.00	23.00	14.00
17		Unattended Tran	115.00	69.00	
18	FREEPORT SUBSTATION	Unattended Dist	69.00	4.00	
19		Unattended Dist	7.00	4.00	
20	FRONTENAC SUBSTATION	Unattended Dist	69.00	13.00	
21	GARFIELD SUBSTATION	Unattended Dist	15.00	4.00	
22	GATEWAY SUBSTATION	Unattended Dist	69.00	14.00	
23	GAYLORD SUBSTATION	Unattended Dist	69.00	4.00	
24	GIBBON SUBSTATION	Unattended Dist	69.00	13.00	
25	GLEASON LAKE SUBSTATION	Unattended Dist	115.00	35.00	
26		Unattended Dist	115.00	14.00	
27		Unattended Tran	115.00	69.00	
28		Unattended Dist	35.00	14.00	
29	GLEN LAKE SUBSTATION	Unattended Dist	69.00	14.00	8.00
30		Unattended Dist			
31	GLENWOOD SUBSTATION	Unattended Dist	69.00	13.00	
32		Unattended Dist	69.00	4.00	
33		Unattended Tran			
34	GOODVIEW SUBSTATION	Unattended Dist	69.00	13.00	8.00
35		Unattended Tran			
36	GOOSE LAKE SUBSTATION	Unattended Dist	115.00	14.00	8.00
37	GOPHER SUBSTATION	Unattended Dist	115.00	14.00	8.00
38	GRANITE CITY SUBSTATION	Unattended Dist	115.00	36.00	21.00
39		Unattended Dist			
40		Unattended Dist	115.00	14.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	GRANT NO CANISTOTA JUNCTION	Unattended Tran	115.00	72.00	2.00
2	GREEN ISLE SUBSTATION	Unattended Dist	69.00	4.00	
3	GREENFIELD SUBSTATION	Unattended Dist	69.00	13.00	
4	HADLEY SUBSTATION	Unattended Dist	69.00	13.00	
5	HARRISBURG SUBSTATION	Unattended Dist	69.00	14.00	
6	HASSAN SUBSTATION	Unattended Dist	115.00	35.00	
7	HASTINGS SUBSTATION	Unattended Dist	69.00	14.00	8.00
8	HATFIELD SUBSTATION	Unattended Dist	23.00	13.00	
9	HATTON SUBSTATION	Unattended Dist	69.00	2.00	
10		Unattended Tran			
11	HECTOR SUBSTATION	Unattended Dist	69.00	4.00	
12					
13	HENDERSON SUBSTATION	Unattended Dist	69.00	13.00	
14	HIGH BRIDGE SUBSTATION	Unattended Dist	115.00	14.00	
15	HOLLYDALE SUBSTATION	Unattended Dist	69.00	14.00	8.00
16		Unattended Dist	36.00	14.00	
17	HOWARD JUNCTION SUBSTATION	Unattended Dist	35.00	13.00	
18	HOWARD LAKE SUBSTATION	Unattended Dist	69.00	14.00	
19	HUGO SUBSTATION	Unattended Dist	115.00	36.00	
20	HYLAND LAKE SUBSTATION	Unattended Dist	115.00	14.00	8.00
21	INDIANA SUBSTATION	Unattended Dist	115.00	14.00	8.00
22	INDUSTRIAL SUBSTATION	Unattended Dist	35.00	13.00	4.00
23		Unattended Dist	35.00	4.00	3.00
24	INVER GROVE STATION	Unattended Tran	115.00	71.00	14.00
25	INVER HILLS SUBSTATION	Unattended Prod	115.00	14.00	
26		Unattended Prod	115.00	14.00	
27		Unattended Tran	345.00	118.00	14.00
28	JORDAN SUBSTATION	Unattended Dist	69.00	13.00	
29	KASSON SUBSTATION	Unattended Dist	69.00	14.00	
30		Unattended Dist			
31	KEGAN LAKE SUBSTATION	Unattended Dist	69.00	14.00	8.00
32	KENYON SUBSTATION	Unattended Dist	69.00	13.00	
33	KIMBALL SUBSTATION	Unattended Dist	69.00	13.00	
34	KOCH REFINERY SUBSTATION	Unattended Dist	115.00	14.00	
35		Unattended Tran			
36	KOHLMAN LAKE SUBSTATION	Unattended Tran	345.00	115.00	13.80
37		Unattended Dist	115.00	14.00	
38	LA CRESCENT SUBSTATION	Unattended Dist	69.00	14.00	8.00
39	LAFAYETTE SUBSTATION	Unattended Dist	69.00	4.00	
40		Unattended Tran			

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	LAKE CITY SUBSTATION	Unattended Dist			
2	LAKE EMILY SUBSTATION	Unattended Dist	69.00	14.00	
3	LAKE LILLIAN SUBSTATION	Unattended Dist	69.00	13.00	
4	LAKE PULASKI SUBSTATION	Unattended Dist	115.00	36.00	
5		Unattended Tran	115.00	69.00	47.00
6			115.00	69.00	7.60
7	LAKE YANKTON STATION	Unattended Dist	69.00	14.00	
8		Unattended Tran	115.00	72.00	
9	LARIMORE SUBSTATION	Unattended Dist	69.00	4.00	
10	LAWRENCE SUBSTATION	Unattended Dist	115.00	36.00	
11		Unattended Tran	115.00	41.00	14.00
12	LENNOX SUBSTATION	Unattended Dist	69.00	13.80	
13	LESTER PRAIRIE SUBSTATION	Unattended Dist	69.00	14.00	
14		Unattended Dist			
15	LESUEUR CAP SUBSTATION	Unattended Tran			
16	LEXINGTON SUBSTATION	Unattended Dist	35.00	14.00	
17		Unattended Dist	115.00	14.00	
18	LINCOLN COUNTY SUBSTATION	Unattended Tran	115.00	69.00	
19		Unattended Dist	115.00	14.00	
20	LIND ROAD SUBSTATION	Unattended Dist	69.00	14.00	
21	LINDE SUBSTATION	Unattended Dist	115.00	14.00	
22		Unattended Dist	14.00		
23	LINDSTROM SUBSTATION	Unattended Dist	69.00	14.00	
24	LYON CO SUBSTATION	Unattended Dist			
25	LINN STREET SUBSTATION	Unattended Dist	69.00	13.00	
26	LITTLEFORK SUBSTATION	Unattended Tran			
27	LONE OAK SUBSTATION	Unattended Dist	115.00		
28	LONG LAKE SUBSTATION	Unattended Dist	115.00	14.00	
29	LOON LAKE SUBSTATION	Unattended Tran	115.00	69.00	14.00
30	LOWRY SUBSTATION	Unattended Dist	69.00	13.00	
31	M.E. INTERNATIONAL SUBSTATION	Unattended Dist	15.00	14.00	
32		Unattended Dist	115.00	14.00	
33	MAIN STREET SUBSTATION	Unattended Dist	115.00	14.00	
34	MANNING SUBSTATION	Unattended Dist	69.00	13.00	
35	MAPLE LAKE SUBSTATION	Unattended Dist	69.00	13.00	
36	MAPLE RIVER SUBSTATION	Unattended Tran	230.00	115.00	
37	MAPLETON SUBSTATION	Unattended Dist	69.00	23.00	
38	MAPLEWOOD SUBSTATION	Unattended Dist	15.00	2.00	
39	MARION SUBSTATION	Unattended Dist	23.00	4.00	
40	MARSHALL MUNICIPAL SWITCHING STATION	Unattended Tran			

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	MARSHALL SUBSTATION	Unattended Dist	14.00	4.00	
2	MAXWELL SUBSTATION	Unattended Dist	115.00	4.00	2.00
3	MAYHEW LAKE SUBSTATION	Unattended Dist	115.00	34.50	
4	MAYNARD DISTRIBUTION SUBSTATION	Unattended Dist	69.00	13.00	
5	MAYNARD XMSN SUB	Unattended Tran	115.00	69.00	
6	MAYVILLE SUBSTATION	Unattended Dist	69.00	13.00	
7		Unattended Dist	69.00	4.00	
8		Unattended Tran			
9	MAZEPPA SUBSTATION	Unattended Dist	69.00	13.00	
10	MEDFORD JUNCTION SUBSTATION	Unattended Dist	69.00	13.00	
11	MEDICINE LAKE SUBSTATION	Unattended Dist	115.00	14.00	
12	MEIRE GROVE SUBSTATION	Unattended Dist	69.00	13.00	
13	MERIDEN SUBSTATION	Unattended Dist	69.00	13.00	
14	MERRIAM PARK SUBSTATION	Unattended Dist	115.00	14.00	
15	MINNEHAHA SUBSTATION	Unattended Dist	115.00	14.00	
16	MINNESOTA LAKE SUBSTATION	Unattended Dist	69.00	4.00	
17	MINNESOTA PIPELINE SUBSTATION	Unattended Dist	115.00	4.00	
18	MINNESOTA VALLEY SUBSTATION	Unattended Dist			
19		Unattended Dist	69.00	23.00	
20		Unattended Prod	115.00	14.00	
21		Unattended Tran	115.00	69.00	
22		Unattended Tran	230.00	115.00	14.00
23	MOBILE CAP MC01 (69KV 5400KVAR)	Unattended Dist			
24	MOBILE CAP MC02 (69KV 5400KVAR)	Unattended Dist			
25	MONTEVIDEO SUBSTATION	Unattended Dist	69.00	14.00	
26		Unattended Dist	69.00	4.00	
27	MONTICELLO SUBSTATION	Unattended Tran	345.00	230.00	
28		Unattended Tran	345.00	115.00	
29		Unattended Tran	15.00		
30		Unattended Prod	345.00	199.00	22.00
31	MONTROSE SUBSTATION	Unattended Dist	69.00	13.00	
32	MOORE LAKE SUBSTATION	Unattended Dist	115.00	14.00	
33		Unattended Dist	115.00	14.00	
34	MORGAN SUBSTATION	Unattended Dist	69.00	23.00	
35	MORRELL SUBSTATION	Unattended Dist	69.00	4.00	
36	MORRISTOWN SUBSTATION	Unattended Dist	69.00	13.00	
37	MORTON QUARRIES SUBSTATION	Unattended Dist	23.00	2.00	
38	MOUND SUBSTATION	Unattended Dist	69.00	14.00	8.00
39	NERSTRAND SUBSTATION	Unattended Dist	69.00	13.00	
40	NEW LONDON SUBSTATION	Unattended Dist	35.00	13.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	NEW RICHLAND SUBSTATION	Unattended Dist	23.00	9.00	
2	NEW RICHLAND SUBSTATION	Unattended Dist			
3	NICOLLET SUBSTATION	Unattended Dist	14.00	4.00	
4	NINE MILE CREEK SUBSTATION	Unattended Dist	115.00	14.00	
5	NOBLES COUNTY (NOB)	Unattended Tran	345.00	115.00	34.50
6	NOBLES COUNTY SUBSTATION	Unattended Tran	115.00	34.50	
7	NORDIC SUBSTATION	Unattended Dist	115.00	14.00	8.00
8	NORTH BROADWAY SUBSTATION	Unattended Dist	23.00	4.00	3.00
9	NORTH FRANKLIN SUBSTATION	Unattended Dist	15.00	7.00	
10	NORTH STAR STEEL SUBSTATION	Unattended Dist	115.00	14.00	
11	NORTHFIELD SUBSTATION	Unattended Dist	69.00	14.00	
12	OAK PARK SUBSTATION	Unattended Dist	115.00	23.00	
13		Unattended Dist	115.00	24.00	14.00
14		Unattended Dist	115.00	14.00	6.00
15	OAKDALE SUBSTATION	Unattended Dist	115.00	14.00	8.00
16	OAKLAND SUBSTATION	Unattended Dist	14.00	4.00	
17	ORONO SUBSTATION	Unattended Dist	69.00	14.00	
18	OSAKIS SUBSTATION	Unattended Dist	69.00	4.00	
19	OSSEO SUBSTATION	Unattended Dist	115.00	14.00	
20	PARK SUBSTATION	Unattended Dist	69.00	4.00	
21	PARKERS LAKE SUBSTATION	Unattended Dist	118.00	14.00	
22		Unattended Dist	115.00	14.00	
23		Unattended Tran	345.00	118.00	
24		Unattended Tran			
25	PATHFINDER SUBSTATION	Unattended Prod	115.00	66.00	14.00
26	PAYNESVILLE SUBSTATION	Unattended Dist	35.00	4.00	
27	PAYNESVILLE TRANSMISSION STATION	Unattended Dist	35.00	13.00	
28		Unattended Tran	115.00	35.00	
29		Unattended Tran	115.00	69.00	14.00
30		Unattended Tran	230.00	115.00	
31	PILLSBURY ROAD SUBSTATION	Unattended Dist	69.00	14.00	
32	PINE BEND SUBSTATION	Unattended Dist	69.00	14.00	8.00
33		Unattended Dist	69.00	4.00	3.00
34	PINE ISLAND SUBSTATION	Unattended Dist	69.00	13.00	
35		Unattended Tran			
36	PIPESTONE SUBSTATION	Unattended Dist	69.00	23.00	
37		Unattended Dist	69.00	4.00	3.00
38		Unattended Tran	115.00	72.00	14.00
39	PLATO SUBSTATION	Unattended Dist	69.00	13.00	
40	PORTAL PIPELINE SUBSTATION	Unattended Dist	15.00	4.00	

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			Primary (c)	Secondary (d)	Tertiary (e)
1	PRAIRIE ISLAND SUBSTATION	Unattended Tran	345.00	161.00	14.00
2		Unattended Prod	345.00	60.00	20.00
3	PRAIRIE SUBSTATION	Unattended Tran	115.00	41.00	14.00
4	PRAIRIE SUBSTATION	Unattended Tran	230.00	115.00	
5	PRIOR SUBSTATION	Unattended Dist	115.00	14.00	8.00
6	QUINCY SUBSTATION	Unattended Dist	14.00	4.00	
7	RAMSEY SUBSTATION	Unattended Dist	115.00	14.00	
8		Unattended Dist			
9		Unattended Dist			
10	RAPIDAN SUBSTATION	Unattended Dist	69.00	23.00	
11	RED RIVER SUBSTATION	Unattended Dist	115.00	24.00	14.00
12		Unattended Dist	115.00	15.00	5.00
13		Unattended Dist	115.00	68.00	15.00
14	RED ROCK STATION	Unattended Dist	115.00	14.00	
15		Unattended Dist	115.00	14.00	8.00
16		Unattended Tran	345.00	230.00	22.00
17		Unattended Tran	345.00	118.00	
18	RED WING SUBSTATION	Unattended Dist	69.00	14.00	
19	RENNER SUBSTATION	Unattended Dist	69.00	13.00	
20	RENVILLE SUBSTATION	Unattended Dist	69.00	13.00	
21	REYNOLDS SUBSTATION	Unattended Dist	69.00	13.00	
22	RICH (CREEK) SPRING SUB	Unattended Dist	69.00	14.00	
23	RICHMOND SUBSTATION	Unattended Dist	69.00	14.00	
24	RIVERSIDE SUBSTATION	Unattended Prod	115.00	67.00	15.00
25		Unattended Dist	115.00	14.00	8.00
26		Unattended Prod	115.00	14.00	
27		Unattended Dist	15.00		
28	RIVERWOOD SUBSTATION	Unattended Dist	115.00	14.00	
29	ROCK RIVER SUBSTATION	Unattended Dist	69.00	23.00	
30	ROCKVILLE SUBSTATION	Unattended Dist	35.00	2.00	
31	ROGERS LAKE STATION	Unattended Dist	115.00	14.00	8.00
32		Unattended Tran			
33	ROSE PLACE SUBSTATION	Unattended Dist	115.00	14.00	8.00
34	ROSEAU COUNTY SUBSTATION	Unattended Tran			
35	ROSEFIELD SUBSTATION	Unattended Dist	14.00	7.00	
36	ROSEMOUNT SUBSTATION	Unattended Dist	115.00	36.00	
37	RUTHTON SUBSTATION	Unattended Dist	23.00	7.00	
38	SACRED HEART SUBSTATION	Unattended Dist	69.00	24.00	
39	SALEM SUBSTATION	Unattended Dist	69.00	35.00	
40		Unattended Dist	69.00	4.00	

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	SALIDA CROSSING SUBSTATION	Unattended Dist	115.00	14.00	
2	SARTELL SUBSTATION	Unattended Dist	35.00	13.00	
3	SAUK RIVER SUBSTATION	Unattended Dist	115.00	36.00	
4	SAVAGE SUBSTATION	Unattended Dist	115.00	13.00	8.00
5		Unattended Dist	115.00	14.00	8.00
6	SCANDIA SUBSTATION	Unattended Dist	69.00	13.00	
7	SCOTT COUNTY STATION	Unattended Tran	115.00	69.00	
8	SEDAN SUBSTATION	Unattended Dist	69.00	8.00	
9	SHAKOPEE SUBSTATION	Unattended Dist	15.00	4.00	2.00
10		Unattended Dist	69.00	14.00	
11	SHEPARD SUBSTATION	Unattended Dist	115.00	14.00	
12	SHERBURNE COUNTY SUBSTATION	Unattended Prod	345.00	24.00	
13		Unattended Prod	345.00	26.00	
14		Unattended Tran	345.00	115.00	13.80
15	SHEYENNE SUBSTATION	Unattended Tran	230.00	115.00	14.00
16	SIBLEY PARK SUBSTATION	Unattended Dist	69.00	14.00	8.00
17	SIBLEY PROPANE PLANT SUBSTATION	Unattended Dist	15.00	2.00	
18	SIOUX FALLS SUBSTATION	Unattended Dist	69.00	14.00	8.00
19		Unattended Dist	34.00	4.00	3.00
20	SLAYTON WEST SUBSTATION	Unattended Dist	69.00	13.80	
21	SOURIS SUBSTATION	Unattended Dist	115.00	14.00	8.00
22		Unattended Dist	118.00	14.00	
23	SOUTH RIDGE SUBSTATION	Unattended Dist	69.00	23.00	
24	SOUTH SIOUX FALLS SUBSTATION	Unattended Dist	69.00	4.00	3.00
25		Unattended Dist	69.00	14.00	8.00
26	SOUTH SUBSTATION	Unattended Tran	69.00	2.00	
27	SOUTHSIDE SUBSTATION	Unattended Dist	34.00	13.00	8.00
28	SOUTHTOWN SUBSTATION	Unattended Dist	115.00	14.00	
29	SPLIT ROCK SUBSTATION	Unattended Tran	161.00	115.00	14.00
30		Unattended Tran	345.00	115.00	14.00
31	SPRING VALLEY SUBSTATION	Unattended Dist	69.00	13.00	
32	ST CLAIR SUBSTATION	Unattended Dist	15.00	4.00	3.00
33	ST CLOUD SUBSTATION	Unattended Dist	115.00	64.00	36.00
34		Unattended Dist			
35	ST JAMES MUNICIPAL SUBSTATION	Unattended Dist	69.00	12.00	7.00
36	ST JAMES SWITCHING STATION	Unattended Tran			
37	ST JOHNS SUBSTATION	Unattended Dist	69.00	5.00	
38	ST JOSEPH SUBSTATION	Unattended Dist	69.00	4.00	3.00
39		Unattended Tran			
40	ST LOUIS PARK SUBSTATION	Unattended Dist	115.00	14.00	

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1		Unattended Dist	115.00	14.00	
2		Unattended Dist	115.00	36.00	
3	ST REGIS (CHAMPION) SUBSTATION	Unattended Dist	115.00	14.00	
4	STEWART SUBSTATION	Unattended Dist	69.00	12.50	
5	STOCKYARDS SUBSTATION	Unattended Dist	115.00	14.00	8.00
6	SUMMIT AVENUE SUBSTATION	Unattended Dist	115.00	14.00	
7	SWAN LAKE SUBSTATION	Unattended Dist	115.00	14.00	8.00
8	TANNERS LAKE SUBSTATION	Unattended Dist	15.00	8.00	7.00
9		Unattended Dist	115.00	14.00	8.00
10	TERMINAL SUBSTATION	Unattended Tran	345.00	118.00	35.00
11		Unattended Dist	115.00	14.00	
12	THOMPSON SUBSTATION	Unattended Dist	69.00	13.00	
13	TRACY SUBSTATION	Unattended Dist	69.00	4.00	
14	TRACY SWITCHING STATION	Unattended Dist	69.00	14.00	8.00
15		Unattended Tran			
16	TRAVERSE SWITCHING STATION	Unattended Tran			
17	TWIN LAKE SUBSTATION	Unattended Dist	115.00	14.00	8.00
18	UPPER LEVEE SUBSTATION	Unattended Dist	115.00	14.00	
19	VERMILLION SUBSTATION	Unattended Dist	15.00		
20	VERMILLION RIVER SUBSTATION	Unattended Dist	115.00	14.00	
21	VESELI SUBSTATION	Unattended Dist	69.00	13.00	
22	VILLARD SUBSTATION	Unattended Dist	69.00	13.00	
23	WABASHA SUBSTATION	Unattended Dist	69.00	13.00	
24		Unattended Dist	69.00	13.00	4.00
25		Unattended Tran			
26	WACONIA SUBSTATION	Unattended Dist	69.00	14.00	8.00
27	WAKEFIELD STATION	Unattended Dist	35.00	14.00	
28		Unattended Dist	69.00	14.00	
29		Unattended Dist	115.00	35.00	
30		Unattended Dist	115.00	40.00	
31	WALDORF SUBSTATION	Unattended Dist	23.00	13.00	
32	WASECA SUBSTATION	Unattended Dist	69.00	4.00	3.00
33		Unattended Dist	69.00	23.00	
34	WATAB RIVER SUBSTATION	Unattended Dist	69.00	13.00	
35	WATER PLANT SUBSTATION	Unattended Dist	69.00	4.00	
36	WATERTOWN SUBSTATION	Unattended Dist	69.00	14.00	
37	WATERVILLE SUBSTATION	Unattended Dist	69.00	23.00	
38		Unattended Dist	69.00	13.00	
39		Unattended Dist	69.00	4.00	
40		Unattended Tran			

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	WATKINS SUBSTATION	Unattended Dist	69.00	4.00	
2	WAVERLY SUBSTATION	Unattended Dist	69.00	13.00	
3	WELLS CREEK SUBSTATION	Unattended Dist	69.00	13.00	
4	WESCOTT LNG PLANT SUBSTATION	Unattended Dist	69.00	2.00	
5		Unattended Dist	14.00	2.00	
6	WEST BYRON SUBSTATION	Unattended Dist	69.00	13.00	
7	WEST COON RAPIDS SUBSTATION	Unattended Dist	35.00	14.00	
8		Unattended Dist	115.00	35.00	
9	WEST FARIBAULT SUBSTATION	Unattended Tran	115.00	69.00	14.00
10		Unattended Dist	69.00	14.00	
11		Unattended Prod	69.00	14.00	
12	WESTGATE STATION	Unattended Dist	115.00	35.00	
13		Unattended Dist	115.00	14.00	
14		Unattended Tran	115.00	69.00	
15	WEST HASTINGS SUBSTATION	Unattended Tran	115.00	69.00	
16		Unattended Dist	115.00	12.50	
17	WEST RIVER ROAD SUBSTATION	Unattended Dist	115.00	14.00	
18	WEST SIOUX FALLS SUBSTATION	Unattended Dist	115.00	14.00	8.00
19		Unattended Tran	115.00	69.00	
20	WEST WACONIA SUBSTATION	Unattended Tran	115.00	35.00	
21	WESTERN SUBSTATION	Unattended Dist	115.00	14.00	8.00
22	WESTPORT SUBSTATION	Unattended Dist	69.00	8.00	
23	WILLIAMS BROTHERS PIPELINE	Unattended Dist	15.00	14.00	
24		Unattended Dist	15.00	4.00	3.00
25		Unattended Dist	115.00	14.00	
26	WILMARTH SUBSTATION	Unattended Dist	69.00	14.00	
27		Unattended Tran	115.00	69.00	
28		Unattended Tran	161.00	115.00	
29		Unattended Tran	345.00	115.00	14.00
30		Unattended Prod	69.00	14.00	
31	WILSON ROAD SUBSTATION	Unattended Dist	69.00	14.00	
32	WILSON SUBSTATION	Unattended Dist	115.00	14.00	
33		Unattended Tran			
34	WINONA SUBSTATION	Unattended Dist	69.00	13.00	
35		Unattended Tran			
36	WINSTED SUBSTATION	Unattended Dist	69.00	14.00	8.00
37	WINTHROP SUBSTATION	Unattended Dist	69.00	4.00	
38	WOODBURY SUBSTATION	Unattended Dist	115.00	36.00	
39	WOODROW SUBSTATION	Unattended Dist	23.00	4.00	3.00
40	WOODSTOCK SUBSTATION	Unattended Dist	23.00	2.00	

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	WYOMING SUBSTATION	Unattended Dist	115.00	13.00	
2		Unattended Dist			
3	YANKEE SUBSTATION	Unattended Tran	115.00	34.50	13.80
4	YELLOW MEDICINE SUBSTATION	Unattended Dist	69.00	23.00	
5	YOUNG AMERICA SUBSTATION	Unattended Dist	69.00	14.00	
6		Unattended Dist			
7	ZUMBRO FALLS SUBSTATION	Unattended Dist	69.00	13.00	
8	ZUMBROTA SUBSTATION	Unattended Dist	69.00	4.00	2.00
9		Unattended Dist	69.00	13.00	
10		Unattended Tran			
11	Total Substations - 364		47248.00	12304.10	1645.20
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					

SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
4	1					1
	3					2
300	1					3
70	1					4
70	1					5
56	2					6
93	2		Cap Bank	9	16	7
6	1		Reg	6	3	8
11	1					9
70	1					10
140	2					11
			Cap Bank	2	253	12
2	3		Reg	3		13
448	1		Ground Bank	3		14
784	1					15
7	1		Reg	3	1	16
2	8					17
14	1		Reg	1	1	18
			Cap Bank	1	5	19
140	2		Cap Bank	2	4	20
	1					21
70	1		Reg	5	3	22
70	1					23
			Ground Bank	2	5	24
6	1					25
1	3		Reg	1		26
14	1		Reg	3		27
14	1		Reg	3	2	28
14	1		Reg	3	1	29
			Cap Bank	1	11	30
1	4		Reg	3	1	31
			Cap Bank	3	180	32
10	2		Reg	15	2	33
28	1					34
93	2					35
28	1					36
			Cap Bank	1	7	37
5	1		Reg	1	1	38
7	1					39
4	1		Reg	3		40

SUBSTATIONS (Continued)

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

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
1	3					1
14	1					2
672	2					3
14	1		Reg	3	1	4
3	1		Reg	3		5
			Cap Bank	1	7	6
336	1					7
712	4					8
			Cap Bank	2	20	9
						10
9	1					11
50	2		Reg	4	2	12
246	2					13
336	1					14
47	1					15
3	1		Reg	3		16
3	3					17
3	3	1				18
448	1					19
448	1					20
53	2					21
6	1		Reg	3	1	22
1	1		Cap Bank	1	5	23
3	1		Reg	1		24
240	2					25
7	1		Reg	1	1	26
11	1					27
2	1		Reg	3		28
			Cap Bank	3	15	29
	1					30
8	1		Reg	1	1	31
5	1					32
			Cap Bank	2	11	33
3	3		Reg	3		34
5	1					35
11	1					36
224	2					37
						38
1	3					39
14	2		Reg	3	1	40

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
			Cap Bank	1	5	1
5	1					2
140	2					3
47	1					4
50	2					5
1	1		Reg	3		6
97	2					7
20	1		Reg	7	5	8
23	1					9
2	1		Reg	3		10
240	2	1				11
			Reg	3	1	12
	1					13
25	1		Reg	1		14
25	1		Cap Bank	4	22	15
37	1		Reg	9	3	16
70	1					17
			Cap Bank	1	40	18
47	1		Reg	3	3	19
448	1		Cap Bank	5	468	20
1200	3		Ground Bank	7	10	21
19	1					22
14	1		Reg	3	2	23
7	1					24
5	1	1	Reg	3	1	25
11	1		Reg	6	2	26
7	1					27
11	1					28
187	1					29
1344	2					30
28	1					31
93	2					32
3	1		Reg	3		33
28	2		Reg	1	2	34
28	1		Cap Bank	2	4	35
93	2					36
10	3					37
22	1					38
53	2					39
112	1					40

SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
14	1		Reg	1	1	1
1	3		Reg	3		2
1	3		Cap Bank	1	8	3
6	1		Reg	6	3	4
188	3		Cap Bank	4	22	5
			Cap Bank	2	4	6
56	2					7
	2					8
11	1		Reg	9	3	9
11	1					10
10	1		Reg	3	1	11
5	1		Cap Bank	1	5	12
14	1					13
8	1					14
47	1		Cap Bank	1	14	15
20	1		Reg	6	2	16
5	1		Reg	2	1	17
140	3					18
11	1					19
56	2					20
1	1		Reg	3		21
94	2					22
896	2					23
2	3		Reg	3		24
1	3		Reg	3		25
2	1					26
210	3		Cap Bank	3	16	27
47	1					28
93	2					29
			Cap Bank	1	120	30
25	1					31
70	1					32
448	1		Cap Bank	1	80	33
2	3		Reg	3		34
13	2					35
	3		Reg	2		36
19	1		Reg	6	2	37
			Cap Bank	2	4	38
			Cap Bank	1	14	39
28	2					40

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
			Cap Bank	1	7	1
28	2					2
			Cap Bank	1	7	3
1	3					4
11	1					5
14	1					6
240	2					7
			Series Cap Bank	1	20	8
11	1		Reg	1		9
			Cap Bank	1	7	10
336	4					11
3	1		Reg	1		12
168	1		Cap Bank	5	1,000	13
70	1		Cap Bank	1	15	14
2	3		Reg	6	1	15
5	3					16
93	1					17
7	1		Reg	5		18
2	3					19
2	1		Reg	1		20
15	6		Reg	30	5	21
56	1					22
5	1		Reg	7	1	23
3	1		Reg	3		24
70	1					25
94	2					26
112	1					27
28	1					28
56	2		Reg	6	6	29
			Cap Bank	1	2	30
5	1		Reg	6	1	31
21	2	1				32
			Cap Bank	1	7	33
56	2					34
			Cap Bank	1	7	35
93	2		Cap Bank	7	13	36
93	2		Cap Bank	5	9	37
70	1		Reg	7	3	38
			Cap Bank	2	160	39
93	2					40

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
19	1					1
2	1					2
5	1		Reg	3	1	3
4	1		Reg	4	1	4
4	1		Reg	3	1	5
140	2					6
56	2		Cap Bank	3	5	7
	3					8
2	1		Reg	3		9
			Cap Bank	1	5	10
3	1		Reg	1		11
			Cap Bank	1	7	12
2	1					13
47	1					14
25	1					15
28	1					16
1	3					17
14	1		Reg	3	1	18
140	2					19
93	2		Cap Bank	5	9	20
94	2		Cap Bank	3	5	21
13	2		Reg	3		22
2	3					23
125	2					24
140	1					25
280	2					26
550	1					27
14	1		Reg	2	1	28
25	2		Reg	6	2	29
			Cap Bank	1	11	30
14	1					31
3	1		Reg	1		32
3	1		Reg	1		33
187	4					34
			Cap Bank	2	83	35
898	2		Cap Bank	3	248	36
97	2					37
11	1					38
1	1		Reg	4		39
			Cap Bank	1	7	40

SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
			Reg	3		1
7	1					2
4	1		Reg	3	1	3
28	1					4
47	1					5
47	1					6
11	1	1	Ground Bank			7
140	2		Cap Bank	4	80	8
5	1		Reg	6	1	9
70	1					10
112	1					11
14	1		Reg	3	1	12
9	1		Reg	1	1	13
			Ground Bank	1	10	14
			Cap Bank	1	5	15
47	1		Cap Bank	4	7	16
147	3					17
70	1		Cap Bank	2	29	18
56	2					19
9	3					20
100	1	1	Ground Bank	3		21
2	1					22
21	2		Reg	1		23
			Cap Bank	2	4	24
21	2		Reg	9	2	25
			Cap Bank	6	180	26
94	2					27
50	2		Reg	5	2	28
112	1		Cap Bank	4	30	29
4	1		Reg	4	4	30
3	1					31
62	2					32
140	2		Cap Bank	13	43	33
4	1					34
7	1		Reg	3	1	35
187	1					36
6	1		Reg	3	1	37
3	3					38
4	1		Reg	3		39
			Cap Bank	5	39	40

SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
5	1		Reg	22	2	1
28	1					2
70	1					3
3	1		Reg	3		4
47	1					5
6	1		Reg	11	9	6
6	1					7
			Cap Bank	1	5	8
5	1		Reg	3	1	9
4	1		Reg	3	1	10
210	3		Cap Bank	6	11	11
2	1		Reg	2		12
3	1		Reg	3	1	13
188	3		Cap Bank	3	16	14
56	2					15
2	1		Reg	3		16
11	1					17
			Reg	2		18
14			Cap Bank	2	80	19
50	1					20
93	2		Cap Bank	2	80	21
374	2					22
			Cap Bank	1	5	23
			Cap Bank	1	5	24
5	1		Reg	9	1	25
6	1		Ground Bank	1	5	26
336	1					27
300	1					28
	1					29
728	1					30
7	1		Reg	3	1	31
47	1		Cap Bank	8	18	32
140	2					33
14	1		Reg	6	4	34
9	1					35
5	1		Reg	3	1	36
1	3					37
56	2		Cap Bank	1	5	38
3	2		Reg	1		39
3	1		Reg	3		40

SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
2	2		Reg	1		1
			Cap Bank	2	1	2
15	3		Reg	21	2	3
94	2					4
1344	2			1	40	5
		1				6
94	2					7
11	2		Reg	2	1	8
1	2					9
143	3					10
56	2		Ground Bank	3	1	11
10	3					12
28	1					13
93	2					14
93	2		Cap Bank	2	11	15
15	6		Reg	18	3	16
22	1					17
3	1		Reg	6	1	18
140	2		Cap Bank	4	7	19
9	1					20
47	1		Cap Bank	6	11	21
94	2					22
900	6		Cap Bank	3	240	23
			Ground Bank	3	1	24
85	1					25
3	1		Reg	3	1	26
12	3	1	Reg	2	1	27
56	2		Cap Bank	2	50	28
93	2		Cap Bank	6	34	29
336	1					30
9	3					31
9	1		Reg	1	1	32
10	2					33
14	2		Reg	4	1	34
			Cap Bank	1	5	35
6	1		Reg	12	2	36
19	2					37
50	2					38
4	1		Reg	6	3	39
10	2					40

SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
224	1					1
1344	2					2
140	2		Cap Bank	7	280	3
672	2					4
28	1					5
10	2		Reg	12	2	6
100	2		Reg	12	6	7
			Cap Bank	4	7	8
			Ground Bank	2	7	9
3	1		Reg	3		10
47	1		Cap Bank	3	18	11
91	1					12
91	1					13
40	2		Reg	5	2	14
47	1					15
336	1		Cap Bank	3	248	16
896	2					17
38	4		Reg	5	4	18
4	1					19
7	1		Reg	3	1	20
7	1		Reg	3		21
14	1		Reg	3	1	22
5	1		Reg	3	1	23
188	1					24
94	2					25
275	1					26
1	1					27
25	1					28
3	1		Reg	3		29
1	6					30
94	2		Cap Bank	5	27	31
			Cap Bank	3	251	32
93	2		Cap Bank	4	7	33
			Cap Bank	4	390	34
	3					35
70	1					36
1	3		Reg	2		37
5	1		Reg	6	1	38
5	3		Reg	3		39
4	1					40

SUBSTATIONS (Continued)

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

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
14	1					1
7	1		Reg	1		2
70	1					3
25	1		Reg	6	4	4
28	1		Cap Bank	5	9	5
14	1		Reg	1	1	6
140	2					7
	1		Reg	1		8
6	3					9
56	2					10
50	2					11
1600	2					12
960	1					13
448	1					14
374	2		Cap Bank	5	200	15
53	2					16
4	3					17
56	2		Cap Bank	7	27	18
1	1					19
14	1		Reg	3	1	20
28	1					21
94	2					22
5	1		Reg	3	1	23
13	2		Reg	8	1	24
56	2		Cap Bank	7	16	25
1	3					26
11	1					27
203	3		Cap Bank	9	23	28
187	1		Cap Bank	2	167	29
896	2					30
4	1					31
10	2		Reg	18	3	32
83	2		Reg	4	2	33
			Ground Bank	2	18	34
14	1					35
			Cap Bank	1	5	36
2	1		Reg	3	3	37
4	1		Reg	12	1	38
			Cap Bank	1	11	39
70	1					40

SUBSTATIONS (Continued)

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
140	2					1
70	1					2
141	3					3
6	1		Reg	3	1	4
93	2		Cap Bank	9	16	5
94	2					6
11	1					7
73	22					8
140	2					9
1344	2					10
164	3		Reg	26	2	11
4	1		Reg	3	1	12
5	1					13
5	1		Reg	1	1	14
			Cap Bank	1	5	15
			Cap Bank	2	15	16
210	3		Cap Bank	18	32	17
210	3					18
	1					19
28	1					20
8	1		Reg	3	1	21
3	1		Reg	3		22
30	2		Reg	3	1	23
2	1					24
			Cap Bank	1	7	25
22	1		Reg	3	2	26
2	3		Reg	1	19	27
1	1		Ground Bank	1	6	28
19	3					29
10	1					30
2	1		Reg	3		31
8	2		Reg	1	1	32
56	2			3	2	33
7	1		Reg	3	1	34
						35
14	1		Reg	6	1	36
14	1		Reg	7	3	37
4	1					38
2	1					39
			Cap Bank	1	7	40

SUBSTATIONS (Continued)

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
3	1		Reg	1		1
4	1		Reg	3	1	2
5	1		Reg	3	1	3
6	3					4
3	1					5
11	1		Reg	3	1	6
28	1		Reg	3	1	7
140	2					8
224	2		Cap Bank	4	46	9
28	2					10
22	1					11
140	2		Cap Bank	3	5	12
140	2		Cap Bank	1	80	13
93	2					14
112	1					15
28	1					16
210	3					17
140	2		Cap Bank	9	16	18
70	1					19
70	1		Cap Bank	1	30	20
140	2		Cap Bank	5	9	21
	2					22
3	1					23
8	1					24
9	1					25
45	3					26
210	3		Reg	6	4	27
187	1		Ground Bank	2	159	28
896	2					29
93	2					30
9	3					31
210	3		Cap Bank	7	20	32
			Cap Bank	1	120	33
84	3					34
			Cap Bank	2	37	35
11	1		Reg	3	1	36
6	1					37
94	2					38
13	2		Reg	15	1	39
	2					40

SUBSTATIONS (Continued)

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

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
56	2		Reg	10	4	1
			Cap Bank	2	4	2
120	1					3
14	1					4
22	2		Reg	6	3	5
			Ground Bank	3	2	6
4	1		Reg	3	1	7
2	3		Reg	9	2	8
14	1					9
			Cap Bank	1	7	10
44216	774	8		1103	6,621	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

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	/ /	2009/Q4
FOOTNOTE DATA			

Schedule Page: 426.8 Line No.: 6 Column: h

1 120 MVA spare stored on site.

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2	Services provided by Xcel Energy Services Inc.			
3	Contribution of Capital	Xcel Energy Inc.	207	-112,735,699
4	Restricted Stock Units and Performance Share Plan	Xcel Energy Inc.	920	562,542
5	Receipts from Utility Money Pool Arrangement	Xcel Energy Services	145	125,500,000
6	Borrowings under Utility Money Pool Arrangement	Xcel Energy Services	233	-601,700,000
7	Utility Money Pool Interest Expense	Xcel Energy Services	430	572,767
8	Advances from Affiliates	NSP-Wisconsin	145	47,000,000
9	Advances from Subsidiaries	Nuclear Management	145	580,000
10	Advances to Subsidiaries	Nuclear Management	233	-330,000
11	Interchange Agreement	NSP-Wisconsin	456	
12		NSP-Wisconsin		
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21	401(k) Match	Xcel Energy Inc.	926	3,405,172
22	Investments in Utility Money Pool Arrangement	Xcel Energy Services	145	-132,500,000
23	Repayments under Utility Money Pool Arrangement	Xcel Energy Services	233	665,200,000
24	Advances to Affiliates	NSP-Wisconsin	145	-62,500,000
25	Advances to Subsidiaries	Nuclear Management	145	-200,000
26	Advances from Subsidiaries	Nuclear Management	233	2,830,000
27	Interchange Agreement	NSP-Wisconsin	456	
28	CWIP-Employee Labor for CPM-Install 2nd Transform	NSP-Wisconsin	107	-270,653
29	CWIP-Employee Labor for MOC - Sub 161KV Upgrade	NSP-Wisconsin	107	-757,817
30	CWIP-Employee Labor for WHEATON Sub 161 KV LINE	NSP-Wisconsin	107	-286,138
31	CWIP-Employee Labor for GIS Gravel Island-New Sub	NSP-Wisconsin	107	-340,570
32	CWIP-Employee Labor for THL-Construct New 3 Lakes	NSP-Wisconsin	107	-255,398
33	CWIP & Non CWIP Employee Labor - Craft Union	NSP-Wisconsin	514,408,925	-425,475
34	Interchange Gas Agreement: Cost of Scada System	NSP-Wisconsin	495	-308,932
35	Railcar Management Services	PSCo	232	-260,068
36	RWIP - Zolo Equipment sold by NSP-Minnesota to SPS	SPS	108	-421,039
37				
38				
39				
40				
41				
42				

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report
Northern States Power Company (Minnesota)		//	2009/Q4
FOOTNOTE DATA			

Schedule Page: 429 Line No.: 2 Column:

Services provided by Xcel Energy Services Inc. are either direct charged when only one company is benefitting from the service provided, otherwise, expenses are allocated based on methodologies described in the FERC Form 60.

Accounting, Financial Reporting & Taxes	107 - CWIP	\$ 31,526
	163 - Stores Exp	42,541
	184 - Clearing	36,076
	186 - Misc Deferred Debits	38,370
	408.1-409.2 - Taxes (Utility and Non-Utility)	564,918
	417-421 - Other Income	(19,195)
	426.1-426.5 - Other Income Deductions	1,001,258
	430-431 - Interest Charges	348,773
	517-532 - Nuclear Power Generation	31,766
	560-573 - Transmission Expenses	4,653
	580-597 - Distribution Expenses	362
	901-905 - Customer Accounts Expenses	57,798
	920-935 - Administrative and General Expenses	12,226,806
Accounting, Financial Reporting & Taxes Total		<u>14,365,652</u>
Aviation Services	408.1 - Taxes other than Income	31,455
	920-935 - Administrative and General Expenses	2,927,055
Aviation Services Total		<u>2,958,510</u>
Business Systems	107 - CWIP	27,976,472
	108 - Accum Dep	47,671
	143 - Other AR	19,862
	182.3 - Reg Assets	821,291
	408.1 - Taxes other than Income	819,822
	417-421 - Other Income	92,550
	426.1-426.5 - Other Income Deductions	2,326
	500-514 - Steam Power Generation	1,672,710
	517-532 - Nuclear Power Generation	7,854,098
	535-545 - Hydraulic Power Generation	4,250
	546-557 - Other Power Generation	345,330
	560-573 - Transmission Expenses	3,833,999
	580-597 - Distribution Expenses	3,983,229
	807 - 813 - Other Gas Supply Expenses	10,812
	824 - Underground Storage Expenses	1,630
	840-841 - Other Storage Expenses	15,998
	850-870 - Transmission Expenses	241,024
	871-893 - Distribution Expenses	2,130,172
	901-905 - Customer Accounts Expenses	9,154,593
	908-909 - Customer Service and Informational Expenses	151,386
	912 - Sales Expenses	1,446
	920-935 - Administrative and General Expenses	39,822,157
Business Systems Total		<u>99,002,828</u>
Business Unit Accounting and Budgeting	107 - CWIP	34,636
	143 - Other AR	18,577
	182.3 - Reg Assets	12,040
	408.1 - Taxes other than Income	301,599
	426.1-426.5 - Other Income Deductions	28,643
	500-514 - Steam Power Generation	577,585

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Northern States Power Company (Minnesota)		//	2009/Q4

FOOTNOTE DATA

	517-532 - Nuclear Power Generation	742,736
	535-545 - Hydraulic Power Generation	10,164
	546-557 - Other Power Generation	1,108,934
	560-573 - Transmission Expenses	27,158
	580-597 - Distribution Expenses	91
	807 - 813 - Other Gas Supply Expenses	21,763
	850-870 - Transmission Expenses	2
	871-893 - Distribution Expenses	7
	901-905 - Customer Accounts Expenses	8
	920-935 - Administrative and General Expenses	3,118,215
Business Unit Accounting and Budgeting Total		<u>6,002,158</u>
Claims Services	408.1 - Taxes other than Income	44,693
	920-935 - Administrative and General Expenses	730,324
Claims Services Total		<u>775,017</u>
Corporate Communications	107 - CWIP	602
	182.3 - Reg Assets	378,770
	186 - Misc Deferred Debits	71,115
	408.1 - Taxes other than Income	175,337
	426.1-426.5 - Other Income Deductions	1,737,317
	500-514 - Steam Power Generation	(602)
	580-597 - Distribution Expenses	48,440
	901-905 - Customer Accounts Expenses	313
	908-909 - Customer Service and Informational Expenses	41,330
	920-935 - Administrative and General Expenses	5,087,228
Corporate Communications Total		<u>7,539,850</u>
Corporate Strategy & Business Development	408.1 - Taxes other than Income	77,685
	426.1-426.5 - Other Income Deductions	660
	908-909 - Customer Service and Informational Expenses	18,847
	920-935 - Administrative and General Expenses	1,279,025
Corporate Strategy & Business Development Total		<u>1,376,217</u>
Customer Service	182.3 - Reg Assets	841,918
	254 - Reg Liab	395,722
	408.1 - Taxes other than Income	1,176,947
	417-421 - Other Income	(21,827)
	426.1-426.5 - Other Income Deductions	1,685
	901-905 - Customer Accounts Expenses	14,282,587
	908-909 - Customer Service and Informational Expenses	808,899
	920-935 - Administrative and General Expenses	2,981,749
Customer Service Total		<u>20,467,680</u>
Energy Delivery Construction, Operations & Maintenance (COM)	107 - CWIP	829,219
	408.1 - Taxes other than Income	555,728
	426.1-426.5 - Other Income Deductions	3,624
	560-573 - Transmission Expenses	4,775,503
	580-597 - Distribution Expenses	2,716,053
	850-870 - Transmission Expenses	616,226
	871-893 - Distribution Expenses	511,436
	908-909 - Customer Service and Informational Expenses	3,924

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

	920-935 - Administrative and General Expenses	2,294,204
Energy Delivery Construction, Operations & Maintenance (COM) Total		<u>12,305,917</u>
Energy Delivery Engineering/Design	107 - CWIP	7,500,690
	108 - Accum Dep	12,601
	143 - Other AR	52,974
	408.1 - Taxes other than Income	213,427
	426.1-426.5 - Other Income Deductions	1,151
	500-514 - Steam Power Generation	(461)
	517-532 - Nuclear Power Generation	39
	546-557 - Other Power Generation	(319)
	560-573 - Transmission Expenses	2,086,247
	580-597 - Distribution Expenses	945,969
	807 - 813 - Other Gas Supply Expenses	471
	850-870 - Transmission Expenses	401,331
	871-893 - Distribution Expenses	16,581
	908-909 - Customer Service and Informational Expenses	1,273
	920-935 - Administrative and General Expenses	808,602
Energy Delivery Engineering/Design Total		<u>12,040,576</u>
Energy Delivery Marketing	408.1 - Taxes other than Income	14,078
	560-573 - Transmission Expenses	13,575
	580-597 - Distribution Expenses	158,924
	920-935 - Administrative and General Expenses	40,998
Energy Delivery Marketing Total		<u>227,575</u>
Energy Markets - Fuel Procurement	143 - Other AR	3,449
	408.1 - Taxes other than Income	75,473
	500-514 - Steam Power Generation	787,822
	807 - 813 - Other Gas Supply Expenses	136,179
	920-935 - Administrative and General Expenses	450,170
Energy Markets - Fuel Procurement Total		<u>1,453,093</u>
Energy Markets Regulated Trading & Marketing	408.1 - Taxes other than Income	394,515
	426.1-426.5 - Other Income Deductions	40,917
	546-557 - Other Power Generation	2,998,356
	560-573 - Transmission Expenses	547,429
	575.1-575.8 - Regional Market Expenses	706,885
	807 - 813 - Other Gas Supply Expenses	255,865
	908-909 - Customer Service and Informational Expenses	90,130
	912 - Sales Expenses	69,568
	920-935 - Administrative and General Expenses	1,965,739
Energy Markets Regulated Trading & Marketing Total		<u>7,069,404</u>
Energy Supply Business Resources	107 - CWIP	993,993
	108 - Accum Dep	5,213
	121 - NonUtility Property	560
	143 - Other AR	70,225
	408.1 - Taxes other than Income	541,845
	426.1-426.5 - Other Income Deductions	790
	500-514 - Steam Power Generation	5,972,911
	517-532 - Nuclear Power Generation	305,253
	535-545 - Hydraulic Power Generation	8,217
	546-557 - Other Power Generation	474,693

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	580-597 - Distribution Expenses	35
	908-909 - Customer Service and Informational Expenses	3,218
	920-935 - Administrative and General Expenses	2,811,390
Energy Supply Business Resources Total		<u>11,188,343</u>
Energy Supply Engineering and Environmental	107 - CWIP	3,263,049
	108 - Accum Dep	428,505
	121 - NonUtility Property	90
	143 - Other AR	41,651
	408.1 - Taxes other than Income	348,748
	426.1-426.5 - Other Income Deductions	10,439
	500-514 - Steam Power Generation	4,051,361
	517-532 - Nuclear Power Generation	240,595
	535-545 - Hydraulic Power Generation	1,795
	546-557 - Other Power Generation	50,421
	560-573 - Transmission Expenses	77,101
	580-597 - Distribution Expenses	191,240
	850-870 - Transmission Expenses	4,922
	871-893 - Distribution Expenses	49,598
	920-935 - Administrative and General Expenses	2,660,425
Energy Supply Engineering and Environmental Total		<u>11,419,940</u>
Executive Management Services	408.1-409.2 - Taxes (Utility and Non-Utility)	113,275
	426.1-426.5 - Other Income Deductions	803,599
	580-597 - Distribution Expenses	11,587
	920-935 - Administrative and General Expenses	3,107,595
Executive Management Services Total		<u>4,036,056</u>
Facilities & Real Estate	107 - CWIP	876,231
	143 - Other AR	(155,203)
	408.1 - Taxes other than Income	54,739
	426.1-426.5 - Other Income Deductions	98,690
	500-514 - Steam Power Generation	2,293,727
	517-532 - Nuclear Power Generation	930,108
	546-557 - Other Power Generation	814,834
	560-573 - Transmission Expenses	1,763,237
	575.1-575.8 - Regional Market Expenses	37,418
	580-597 - Distribution Expenses	756,171
	807 - 813 - Other Gas Supply Expenses	90,271
	850-870 - Transmission Expenses	34,297
	871-893 - Distribution Expenses	269,837
	920-935 - Administrative and General Expenses	17,674,448
Facilities & Real Estate Total		<u>25,538,805</u>
Facilities Administrative Services	107 - CWIP	874
	408.1 - Taxes other than Income	(24)
	920-935 - Administrative and General Expenses	(100)
Facilities Administrative Services Total		<u>750</u>
Finance & Treasury	182.3 - Reg Assets	4,295
	186 - Misc Deferred Debits	1,615
	408.1 - Taxes other than Income	270,968
	417-421 - Other Income	(20,622)
	426.1-426.5 - Other Income Deductions	989

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

	430-431 - Interest Charges	246,975
	546-557 - Other Power Generation	153,267
	580-597 - Distribution Expenses	4,811
	807 - 813 - Other Gas Supply Expenses	1,161
	908-909 - Customer Service and Informational Expenses	32,434
	920-935 - Administrative and General Expenses	6,923,174
Finance & Treasury Total		<u>7,619,067</u>
Fleet	107 - CWIP	154,642
	184 - Clearing	489,809
	580-597 - Distribution Expenses	167
	920-935 - Administrative and General Expenses	8
Fleet Total		<u>644,626</u>
Government Affairs	107 - CWIP	392,392
	186 - Misc Deferred Debits	7
	408.1-409.2 - Taxes (Utility and Non-Utility)	194,626
	426.1-426.5 - Other Income Deductions	1,675,430
	517-532 - Nuclear Power Generation	60,622
	546-557 - Other Power Generation	14,020
	560-573 - Transmission Expenses	26,421
	920-935 - Administrative and General Expenses	2,525,903
Government Affairs Total		<u>4,889,421</u>
Human Resources	107 - CWIP	55,053
	108 - Accum Dep	18,281
	143 - Other AR	21
	182.3 - Reg Assets	65
	186 - Misc Deferred Debits	16,814
	408.1 - Taxes other than Income	682,232
	426.1-426.5 - Other Income Deductions	37,068
	500-514 - Steam Power Generation	1,429,403
	517-532 - Nuclear Power Generation	5,983
	546-557 - Other Power Generation	867
	560-573 - Transmission Expenses	13,710
	580-597 - Distribution Expenses	1,118
	901-905 - Customer Accounts Expenses	20,208
	908-909 - Customer Service and Informational Expenses	174,765
	920-935 - Administrative and General Expenses	14,844,363
Human Resources Total		<u>17,299,951</u>
Internal Audit	408.1 - Taxes other than Income	98,943
	426.1-426.5 - Other Income Deductions	381
	920-935 - Administrative and General Expenses	1,583,163
Internal Audit Total		<u>1,682,487</u>
Investor Relations	408.1 - Taxes other than Income	18,481
	426.1-426.5 - Other Income Deductions	1,468
	920-935 - Administrative and General Expenses	1,211,645
Investor Relations Total		<u>1,231,594</u>
Legal	107 - CWIP	169,351
	186 - Misc Deferred Debits	7,115
	408.1 - Taxes other than Income	268,775
	426.1-426.5 - Other Income Deductions	6,198

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	500-514 - Steam Power Generation	481
	517-532 - Nuclear Power Generation	113,124
	546-557 - Other Power Generation	(3)
	560-573 - Transmission Expenses	1
	580-597 - Distribution Expenses	32,787
	908-909 - Customer Service and Informational Expenses	1,115
	920-935 - Administrative and General Expenses	5,196,549
Legal Total		<u>5,795,493</u>
Marketing & Sales	182.3 - Reg Assets	5,173,610
	186 - Misc Deferred Debits	764
	408.1-409.2 - Taxes (Utility and Non-Utility)	174,594
	417-421 - Other Income	4,890
	426.1-426.5 - Other Income Deductions	3,695
	901-905 - Customer Accounts Expenses	3,875
	908-909 - Customer Service and Informational Expenses	4,123,355
	912 - Sales Expenses	429
	920-935 - Administrative and General Expenses	3,542,988
Marketing & Sales Total		<u>13,028,200</u>
Payment & Reporting	408.1 - Taxes other than Income	23,968
	920-935 - Administrative and General Expenses	438,899
Payment & Reporting Total		<u>462,867</u>
Payroll	408.1 - Taxes other than Income	21,528
	920-935 - Administrative and General Expenses	458,168
Payroll Total		<u>479,696</u>
Rates & Regulation	107 - CWIP	140,814
	186 - Misc Deferred Debits	7,729
	408.1 - Taxes other than Income	336,970
	426.1-426.5 - Other Income Deductions	1,368
	500-514 - Steam Power Generation	(83)
	517-532 - Nuclear Power Generation	243
	546-557 - Other Power Generation	(198)
	560-573 - Transmission Expenses	5,339
	575.1-575.8 - Regional Market Expenses	939
	920-935 - Administrative and General Expenses	5,210,137
Rates & Regulation Total		<u>5,703,258</u>
Receipts Processing	408.1 - Taxes other than Income	19,999
	901-905 - Customer Accounts Expenses	331,122
	920-935 - Administrative and General Expenses	167,672
Receipts Processing Total		<u>518,793</u>
Supply Chain	107 - CWIP	51,410
	108 - Accum Dep	71,787
	163 - Stores Exp	5,343,221
	408.1 - Taxes other than Income	36,025
	500-514 - Steam Power Generation	1,913
	560-573 - Transmission Expenses	1,080
	920-935 - Administrative and General Expenses	591,400
Supply Chain Total		<u>6,096,836</u>

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FOOTNOTE DATA			

Supply Chain Special Programs	408.1 - Taxes other than Income	4,295
	920-935 - Administrative and General Expenses	119,696
Supply Chain Special Programs Total		123,991
Grand Total		<u>\$303,344,651</u>

Schedule Page: 429 Line No.: 3 Column:

Includes \$7,264,301 allocation of holding company tax benefit.

Schedule Page: 429 Line No.: 11 Column:

See Note 11 to the Financial Statements on Page 122. For amounts billed between NSP-Minnesota and NSP-Wisconsin, refer to Page 300 and Pages 320-323.

Schedule Page: 429 Line No.: 27 Column:

See Note 11 to the Financial Statements on Page 122. For amounts billed between NSP-Minnesota and NSP-Wisconsin, refer to Page 300 and Pages 320-323.

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