THIS FILING IS (CHECK ONE BOX FOR EACH ITEM)		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____
Item 2: ☐ An Original Signed Form	OR ☒	Conformed Copy

Form Approved
OMB No. 1902-0021
(Expires 7/31/98)

50-263
50-282
50-306

FERC Form No. 1:
ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHERS

This report is mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1. 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 this report to be of a confidential nature.

M004
0/1

Exact Legal Name of Respondent (Company)	Year of Report
NORTHERN STATES POWER COMPANY (MINNESOTA)	Dec. 31, 19 96

INSTRUCTIONS FOR FILING THE

FERC FORM NO. 1

GENERAL INFORMATION

I. Purpose

This form is a regulatory support requirement (18 CFR 141.1). It is designed to collect financial and operational information from major electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. This report is also secondarily considered to be a nonconfidential public use form supporting a statistical publication (Financial Statistics of Selected Electric Utilities), published by the Energy Information Administration.

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 CFR 101), must submit this form.

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 this form on electronic media consisting of two (2) duplicate data diskettes and an original and six (6) conformed paper copies, properly filed in and attested, to:

Office of the Secretary
Federal Energy Regulatory Commission
888 First Street, NE.
Room 1A-21
Washington, DC 20426

Retain one copy of this report for your files.

Include with the original and each conformed paper copy of this form the subscription statement required by 18 C.F.R. 385.2011(c)(5). Paragraph (c)(5) of 18 C.F.R. 385.2011 requires each respondent submitting data electronically to file a subscription stating that the paper copies contain the same information as contained on the electronic media, that the signer knows the contents of the paper copies and electronic media, and that the contents as stated in the copies and on the electronic media are true to the best knowledge and belief of the signer.

(b) Submit immediately upon publication, four (4) copies of the latest annual report to stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. (Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Page 4, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared.) Mail these reports to:

Chief Accountant
Federal Energy Regulatory Commission
888 First Street, NE.
Room 1A-21
Washington, DC 20426

(c) For the CPA certification, submit with the original submission, or within 30 days after the filing date for this form, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984):

(i) Attesting to the conformity, in all material aspects, of the below listed (schedules and) pages with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

(ii) 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 CFR 41.10-41.12 for specific qualifications.)

9703055

III. What and Where to Submit (Continued)

(c) Continued

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

When accompanying this form, insert the letter or report immediately following the cover sheet. When submitting after the filing date for this form, send the letter or report to the Office of the Secretary at the address indicated at III (a).

Use the following form for the letter or report 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.

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

(d) Federal, State and Local Governments and other authorized users may obtain additional blank copies to meet their requirements free of charge from:

Public Reference and Files Maintenance Branch
Federal Energy Regulatory Commission
888 First Street, NE.
Room 2A-1 ED-12.2
Washington, DC 20426
(202) 208-2474

IV. When to Submit:

Submit this report form on or before April 30th of the year following the year covered by this report.

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for this collection of information is estimated to average 1,217 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. Send comments regarding this burden estimate or any aspect of this collection of information, including suggestions for reducing this burden, to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 (Attention: Mr. Michael Miller, ED-12.3); 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).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR 101) (U.S. of A.). Interpret all accounting words and phrases in accordance with the U. S. of A.

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 year, and use for statement of income accounts the current year's amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous annual 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, 3, and 4.

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). The date of the resubmission must be reported in the header for all form pages, whether or not they are changed from the previous filing.

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, two (2) new data diskettes and an original and six (6) conformed paper copies of the entire form, as well as the appropriate number of copies of the subscription statement indicated at instruction III (a) must be filed. Resubmissions must be numbered sequentially both on the diskettes and on the cover page of the paper copies of the form. In addition, the cover page of each paper copy must indicate that the filing is a resubmission. Send the resubmissions to the address indicated at instruction III (a).

VIII. Do not make references to reports of previous years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous year, the figures reported must be based upon those shown by the annual report of the previous year, or an appropriate explanation given as to why the different figures were used.

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 wit:
...(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 on the business of developing, transmitting, utilizing, 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 forebay reservoirs directly connected therewith, the primary line or lines transmitting power therefrom 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 form in which such reports shall be made, amd 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."

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, amend, 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 form or 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

"Sec. 315. (a) Any licensee or public utility which willfully fails, within the time prescribed by the Commission, to comply with any order of the Commission, to file any report required under this Act or any rule or regulation of the Commission thereunder, to submit any information of document required by the Commission in the course of an investigation conducted under this Act,...shall forfeit to the United States an amount not exceeding $1,000 to be fixed by the Commission after notice and opportunity for hearing...."

FERC FORM NO. 1:

ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Northern States Power Company (Minnesota)	02 Year of Report Dec. 31, 1996

03 Previous Name and Date of Change (if name changed during year)

04 Address of Principal Office at End of Year (Street, City, State, Zip Code)
414 Nicollet Mall, Minneapolis, Minnesota 55401

05 Name of Contact Person Patricia J. Walstad	06 Title of Contact Person Admin-External Financial Rpts

07 Address of Contact Person (Street, City, State, Zip Code)
414 Nicollet Mall, Minneapolis, Minnesota 55401

08 Telephone of Contact Person, including Area Code 612-330-6820	09 This Report is (1) x An Original (2) A Resubmission	10 Date of Report (Mo, Da, Yr)

ATTESTATION

The undersigned officer certifies that he/she has examined the accompanying report, that to the best of his / her knowledge information and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from and including January 1 to and including December 31 of the year of the report.

01 Name Mr. Roger D. Sandeen 02 Title Vice President and Controller	03 Signature Roger D. Sandeen	04 Date Signed (Mo, Da, Yr) 04/30/97

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

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

LIST OF SCHEDULES (Electric Utility)

Enter in column (d) 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"

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits) (Continued)			
Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes	261	Ed. 12-96	
Taxes Accrued, Prepaid and Charged During Year	262 - 263	Ed. 12-96	
Accumulated Deferred Investment Tax Credits	266 - 267	Ed. 12-89	
Other Deferred Credits	269	Ed. 12-88	
Accumulated Deferred Income Taxes -- Accelerated Amortization Property	272 - 273	Ed. 12-96	
Accumulated Deferred Income Taxes -- Other Property	274 - 275	Ed. 12-96	
Accumulated Deferred Income Taxes -- Other	276 - 277	Ed. 12-96	
Other Regulatory Liabilities	278	Ed. 12-94	
INCOME ACCOUNT SUPPORTING SCHEDULES			
Electric Operating Revenues	300 - 301	Ed. 12-96	
Sales of Electricity by Rate Schedules	304	Ed. 12-95	
Sales of Resale	310 - 311	Ed. 12-88	
Electric Operation and Maintenance Expenses	320 - 323	Ed. 12-95	
Number of Electric Department Employees	323	Ed. 12-93	
Purchased Power	326 - 327	Ed. 12-95	
Transmission of Electricity for Others	328 - 330	Ed. 12-90	
Transmission of Electricity by Others	332	Ed. 12-90	
Miscellaneous General Expenses -- Electric	335	Ed. 12-94	
Depreciation and Amortization of Electric Plant	336 - 337	Ed. 12-95	
Particulars Concerning Certain Income Deduction and Interest Charges Accounts	340	Ed. 12-87	
COMMON SECTION			
Regulatory Commission Expenses	350 - 351	Ed. 12-96	
Research, Development and Demonstration Activities	352 - 353	Ed. 12-87	
Distribution of Salaries and Wages	354 - 355	Ed. 12-88	
Common Utility Plant and Expenses	356	Ed. 12-87	
ELECTRIC PLANT STATISTICAL DATA			
Electric Energy Account	401	Rev. 12-90	
Monthly Peaks and Output	401	Rev. 12-90	
Steam-Electric Generating Plant Statistics (Large Plants)	402 - 403	Rev. 12-95	
Hydroelectric Generating Plant Statistics (Large Plants)	406 - 407	Ed. 12-89	
Pumped Storage Generating Plant Statistics (Large Plants)	408 - 409	Ed. 12-88	not applicable
Generating Plant Statistics (Small Plants)	410 - 411	Ed. 12-87	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
ELECTRIC PLANT STATISTICAL DATA (Continued)			
Transmission Line Statistics	422 - 423	Ed. 12-87	
Transmission Lines Added During Year	424 - 425	Ed. 12-86	
Substations	426 - 427	Ed. 12-96	
Electric Distribution Meters and Line Transformers	429	Ed. 12-88	
Environmental Protection Facilities	430	Ed. 12-88	
Environmental Protection Expenses	431	Ed. 12-88	
Footnote Data	450	Ed. 12-87	not applicable

Stockholders' Reports   Check appropriate box:

[X] Four copies will be submitted.

[ ] No annual report to stockholders is prepared.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 the office where any other corporate books are kept, if different from that where the general corporate books are kept.

Roger D. Sandeen
Vice President and Controller
414 Nicollet Mall
Minneapolis, Minnesota 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.

The respondent was incorporated under the laws of the State of Minnesota in June 1909.

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

During the year 1996 the respondent furnished electric utility and gas utility service in the States of Minnesota and North Dakota; and electric utility 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 the principal accountant for your previous year's certified financial statements?

Yes...Enter the date when such independent accountant was initially engaged:

X No

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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	Northern States Power Company (Wisconsin)	Electric and gas utility	100.00	
2	* Chippewa and Flambeau Improvement Company	Owning and operating water	75.86	
3		storage reservoirs		
4	* Clearwater Investments, Inc.	Affordable housing	100.00	
5	* NSP Lands, Inc.	Real estate holdings	100.00	
6	United Power and Land Company	Real estate holdings	100.00	
7	Cormorant Corporation	Former owner of interest in	100.00	
8		coal and lignite properties		
9	First Midwest Auto Park, Inc.	Parking Ramp	100.00	
10	Cenerprise, Inc.	Natural gas marketing and	100.00	
11		energy services		
12	* Energy Masters Corporation	Energy efficiency	80.00	
13		improvement services		
14	Viking Gas Transmission Company	Natural gas transmission	100.00	
15	Eloigne Company	Affordable housing	100.00	
16	NRG Energy, Inc.	Non-regulated energy products	100.00	
17		and services		
18	* Cobee Holdings Inc.	Independent power producer	100.00	
19	* Elk River Resource Recovery, Inc.	Waste processing	100.00	
20	* Fresh Kills Cogen Inc.	Cogeneration	100.00	
21	* Golden Gate Energy I, Inc.	Cogeneration	100.00	
22	* Golden Gate Energy II, Inc.	Cogeneration	100.00	
23	* Graystone Corporation	Uranium Enrichment	100.00	
24	* Hanford Energy I, Inc.	Cogeneration	100.00	
25	* NEO Corporation	Landfill gas/cogeneration	100.00	
26	* New Roads Generating LLC	Cogeneration	100.00	
27	* NRG Construction Services, Inc.	Construction services	100.00	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

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

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	* NRG Energy Center, Inc.	District heating and cooling	100.00	
2		system		
3	* NRG Energy Jackson Valley I, Inc.	Waste-fuel/cogeneration	100.00	
4	* NRG Energy Jackson Valley II, Inc.	Waste-fuel/cogeneration	100.00	
5	* NRG Hartford, Inc.	Real estate holding company	100.00	
6	* NRG International, Inc.	International business	100.00	
7	* NRG Operating Services, Inc.	Energy project operating and	100.00	
8		maintenance services		
9	* NRG Parlin, Inc.	Cogeneration	100.00	
10	* NRG Services Corporation	Employee services	100.00	
11	* NRG Sunnyside, Inc.	Waste-coal	100.00	
12	* NRG Sunnyside Operations GP, Inc.	Waste-coal	100.00	
13	* NRG Sunnyside Operations LP, Inc.	Waste-coal	100.00	
14	* NRG Yallourn Operations I, Inc.	Independent power producer	100.00	
15	* NRG Yallourn Operations II, Inc.	Independent power producer	100.00	
16	* O'Brien Cogeneration, Inc. II	Cogeneration	100.00	
17	* Okeechobee Power I, Inc.	Independent power producer	100.00	
18	* Okeechobee Power II, Inc.	Independent power producer	100.00	
19	* Okeechobee Power III, Inc.	Independent power Producer	100.00	
20	* Oklahoma Loan Acquisition Corp.	Cogeneration	100.00	
21	* Prairie Wind Energy, Inc.	Domestic business development	100.00	
22	* San Joaquin Valley Energy I, Inc.	Biomass waste-fuel/	100.00	
23		cogeneration		
24	* San Joaquin Valley Energy IV, Inc.	Biomass waste-fuel/	100.00	
25		cogeneration		
26	* Scoria Incorporated	Coal drying facility	100.00	
27	* Wolverine Energy I, Inc.	Cogeneration	100.00	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

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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	* Wolverine Energy II, Inc.	Cogeneration	100.00	
2	Northern Power Wisconsin, Corp.	Formed for purposes of merger	100.00	
3		with Wisconsin Energy Corp.		
4	Seren Innovations, Inc.	Energy mgmt., security cntr,	100.00	
5		and business infor. services		
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< Page 103 Line 2 Column a >

Chippewa and Flambeau Improvement Company
- Indirect control through the Wisconsin Company

< Page 103 Line 4 Column a >

Clearwater Investments, Inc.
- Indirect control through the Wisconsin Company

< Page 103 Line 5 Column a >

NSP Lands, Inc.
- Indirect control through the Wisconsin Company

< Page 103 Line 12 Column a >

Energy Masters Corporation
- Indirect control through Cenerprise Inc.

< Page 103 Line 18 Column a >

Cobee Holdings Inc.
- Indirect control through NRG Energy, Inc.

< Page 103 Line 19 Column a >

Elk River Resource Recovery, Inc.
- Indirect control through NRG Energy, Inc.

< Page 103 Line 20 Column a >

Fresh Kills Cogen Inc.
- Indirect control through NRG Energy, Inc.

< Page 103 Line 21 Column a >

Golden Gate Energy I, Inc.
- Indirect control through NRG Energy, Inc.; Dissolved in 1996.

< Page 103 Line 22 Column a >

Golden Gate Energy II, Inc.
- Indirect control through NRG Energy, Inc.; Dissolved in 1996.

< Page 103 Line 23 Column a >

Graystone Corporation
- Indirect control through NRG Energy, Inc.

< Page 103 Line 24 Column a >

Hanford Energy I, Inc.
- Indirect control through NRG Energy, Inc.; Dissolved in 1996.

< Page 103 Line 25 Column a >

NEO Corporation
- Indirect control through NRG Energy, Inc.

< Page 103 Line 26 Column a >

New Roads Generating LLC
- Indirect control through NRG Energy, Inc.

< Page 103 Line 27 Column a >

NRG Construction Services, Inc.
- Indirect control through NRG Energy, Inc.; Dissolved in 1996.

< Page 103.1 Line 1 Column a >

NRG Energy Center, Inc.
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 3 Column a >

NRG Energy Jackson Valley I, Inc.
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 4 Column a >

NRG Energy Jackson Valley II, Inc.
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 5 Column a >

NRG Hartford, Inc.
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 6 Column a >

NRG International, Inc.
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 7 Column a >

NRG Operating Services, Inc.
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 9 Column a >

NRG Parlin, Inc.
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 10 Column a >

NRG Services Corporation
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 11 Column a >

NRG Sunnyside, Inc.
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 12 Column a >

NRG Sunnyside Operations GP, Inc.
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 13 Column a >

NRG Sunnyside Operations LP, Inc.
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 14 Column a >

NRG Yallourn Operations I, Inc.
- Indirect control through NRG Energy, Inc.; Dissolved in 1996.

< Page 103.1 Line 15 Column a >

NRG Yallourn Operations II, Inc.
- Indirect control through NRG Energy, Inc.; Dissolved in 1996.

< Page 103.1 Line 16 Column a >

O'Brien Cogeneration, Inc. II
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 17 Column a >

Okeechobee Power I, Inc.
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 18 Column a >

Okeechobee Power II, Inc.
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 19 Column a >

Okeechobee Power III, Inc.
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 20 Column a >

Oklahoma Loan Acquisition Corp.
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 21 Column a >

Prairie Wind Energy, Inc.
- Indirect control through NRG Energy, Inc.; Dissolved in 1996.

< Page 103.1 Line 22 Column a >

San Joaquin Valley Energy I, Inc.
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 24 Column a >

San Joaquin Valley Energy IV, Inc.
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 26 Column a >

Scoria Incorporated
- Indirect control through NRG Energy, Inc.

< Page 103.1 Line 27 Column a >

Wolverine Energy I, Inc.
- Indirect control through NRG Energy, Inc.; Dissolved in 1996.

< Page 103.2 Line 1 Column a >

Wolverine Energy II, Inc.
- Indirect control through NRG Energy, Inc.; Dissolved in 1996.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

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 policymaking 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, President & Chief Exec Officer	James J Howard	
2	Vice President & Chief Financial Officer	Edward J McIntyre	
3	Vice President, General Counsel & Corporate Secretary	Gary R Johnson	
4	President - NSP Electric	Loren L Taylor	
5	Vice President - Finance & Treasurer	Arland D Brusven	
6	Vice President - Human Resources	Cynthia L Lesher	
7	Vice President, Controller & Chief Information Officer	Roger D Sandeen	
8	President - NSP Gas	Keith H Wietecki	
9	President - NSP Generation	Douglas D Antony	
10	Vice President & Treasurer	* Jackie A Currier	
11	Vice President - Nuclear Generation	Edward L Watzl	
12	Vice President - Public & Government Affairs	Thomas A Micheletti	
13			
14			
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43	< Page 104 Line 10 Column b >		
44	Resigned 4/30/96 (Currier)		

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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.

Name (and Title) of Director (a)	Principal Business Address (b)
H. Lyman Bretting	P O Box 113, 3401 E. Main Street Ashland, Wisconsin 54806
David A. Christensen	P O Box 5107, 205 E. 6th Street Sioux Falls, South Dakota 57117-5107
W. John Driscoll	2090 First National Bank Bldg. 332 Minnesota Street St. Paul, Minnesota 55101
Dale L. Haakenstad	1207 26th Avenue South #16 Fargo, North Dakota 58103
James J. Howard, Chairman, President and CEO	414 Nicollet Mall Minneapolis, Minnesota 55401
Allen F. Jacobson	3050 Minnesota World Trade Center 30 East Seventh Street St. Paul, Minnesota 55101
Richard M. Kovacevich	Sixth and Marquette, 90 S. 7th Street Minneapolis, Minnesota 55479-1062
Douglas W. Leatherdale	385 Washington Street St. Paul, Minnesota 55102
John E. Pearson	4900 IDS Tower 80 South 8th Street Minneapolis, Minnesota 55402
G. M. Pieschel	P O Box 126, 101 N. Marshall Springfield, Minnesota 56087
Dr. Margaret R. Preska	1175 W. Wabasha Winona, Minnesota 55987
A. Patricia Sampson	3385 Sycamore Lane N Plymouth, Minnesota 55441

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

SECURITY HOLDERS AND VOTING POWERS

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year had the highest voting powers in the respondent, and state the number of votes which each would have had the right to cast on that date if a meeting were then in order. If any such holder held in trust, give in a footnote the known particulars of the trust(whether voting trust, etc.) duration of trust, and principal holders of beneficiary interests in the trust. If the stock book was not closed or a list of stockholders was not compiled within one year prior to the end of the year, or if since the previous compilation of a list of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.

2. If any security other than stock carries voting rights, explain in a footnote the circumstances whereby such security became vested with voting rights and give other important particulars (details) concerning the voting rights of such security. State whether voting rights are actual or contingent; if contingent, describe the contingency.

3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.

4. Furnish particulars (details) concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or rights.Specify the amount of such securities or assets so entitled to be purchased by any officer, director, associated company, or any of the ten largest security holders. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants, or rights were issued on a prorata basis.

1. Give date of the latest closing of the stock book prior to end of year, and state the purpose of such closing:	2. State the total number of votes cast at the latest general meeting prior to end of year for election of directors or the respondent and number of such votes cast by proxy	3. Give the date and place of such meeting:
The stock book was not closed.	Total: 60,832,681 By proxy: 60,830,548	April 24, 1996 1301 So. 2nd Ave. Minneapolis, MN 55463

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES Number of votes as of (date): December 31, 1996 Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
4	TOTAL votes of all voting securities	72,013,712	69,063,712	* 825,000	* 2,125,000
5	TOTAL number of security holders	88,250	86,337	853	1,060
6	TOTAL votes of Security holders listed below	55,638,390	53,231,521	451,422	1,955,447
7	Cede & Co				
8	Box 20, Bowling Green Station				
9	New York, New York	43,472,487	41,099,641	442,290	1,930,556
10					
11	First Trust Co., Inc				
12	Trustee of NSP-ESOP				
13	W555 First National Bank Building				
14	St. Paul, MN	5,871,201	5,871,201		
15					
16	NSP Agent				
17	414 Nicollet Mall				
18	Minneapolis, MN	5,599,245	5,599,245		

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

SECURITY HOLDERS AND VOTING POWERS (Continued)

Line No.	Name (Title) and Address of Security Holder (a)	Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
19	Philadep & Co				
20	1900 Market Street				
21	Philadelphia, PA	518,168	486,645	9,132	22,391
22					
23	Mercantile Bank of Kansas-Trustee of the				
24	Energy Masters Corp. 401(k)				
25	6940 Mission Road				
26	Prairie Village, Kansas 66208	44,027	44,027		
27					
28	Personal Service Insurance				
29	P O Box 1226				
30	Columbus, OH	34,800	32,300		2,500
31					
32	Donald O Smith				
33	6600 Rainbow				
34	Mission Hills, Kansas 66207	28,757	28,757		
35					
36	West Publishing				
37	P O Box 64526				
38	St. Paul, MN	25,000	25,000		
39					
40	Harry G. Gray				
41	9816 Jarboe				
42	Kansas City, MO 64114	22,922	22,922		
43					
44	Harry H. Hetz				
45	74 Robsart Road				
46	Kenilworth, IL 60043	21,783	21,783		
47					
48					
49	*				
50	* See Note 4 of the Notes to the				
51	Financial Statements for discussion of				
52	stock options and other performance				
53	awards.				

< Page 106 Line 4 Column d >

Cumulative Preferred Stock $3.60 series.

< Page 106 Line 4 Column e >

All other series of Cumulative Preferred Stock. Instruction 3. The holders of the 275,000 shares of Preferred Stock of the $3.60 series are entitled to three votes for each share held, and the holders of all other series are entitled to one vote for each share held, provided however, that when dividends payable on the Preferred Stock of any series outstanding are in default in an amount equivalent to four quarter-yearly dividends thereon, and until such default shall have been remedied, the holders of shares of Preferred Stock, voting as a class, are entitled to elect the smallest number of directors necessary to constitute a majority of the Board of Directors and the holders of shares of Common Stock voting as a class, are entitled to elect the remaining directors.

In electing directors, shareholders may cumulate their votes in the manner provided in the Minnesota Business Corporation Act.

The affirmative vote of consent of the holders of various specified percentages of Preferred Stock is required to (A) increase the authorized amount or (B) prejudicially change the terms of the Preferred Stock, authorize stock (A) senior to or (B) on a parity with the Preferred Stock, issue additional Preferred Stock unless certain net income and capital ratio requirements are met, issue or assume unsecured indebtedness under specified conditions, or merge or consolidate under specified conditions.

< Page 107 Line 49 Column a >

Under the provisions of the Company's merger agreement with Wisconsin Energy Corporation (WEC), WEC has the right to purchase, under certain circumstances, up to 13,387,772 shares of the Company's common stock at a price of $44.075 per share. WEC may exercise this option only if the merger agreement becomes terminable by WEC under circumstances which could entitle WEC to termination fees as set forth in the merger agreement. WEC's option will terminate upon either the closing of the merger or the termination of the merger agreement.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

IMPORTANT CHANGES DURING THE 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 therefor 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 conditions. 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.

PAGE 108 INTENTIONALLY LEFT BLANK

SEE PAGE 109 FOR REQUIRED INFORMATION

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

IMPORTANT CHANGES DURING THE YEAR (Continued)

ITEM NUMBER 1 - Respondent renewed franchises from representative local government bodies of the following incorporated communities without payment of consideration.

City	Date of Expiration
Lauderdale, MN - Electric	06-30-1997
Lauderdale, MN - Gas	06-30-1997
St. Paul, MN - Electric	06-30-2006
St. Paul, MN - Gas	06-30-2006
Lakeland Shores, MN - Electric	04-03-2016
Avon, MN - Electric	08-04-2016
Waite Park, MN - Gas	06-03-2016
Sartell, MN - Electric	11-11-2016
Sartell, MN - Gas	11-11-2016
Hastings, MN - Electric	11-17-2016
Kellogg, MN - Electric	12-10-2016

Respondent secured a new franchise from the representative local government body of the following incorporated community without payment of consideration.

City	Date of Expiration
Horace, ND - Gas	10-15-2016

ITEM NUMBER 2 - See Note 14 in the Notes to the Financial Statements for a discussion of the Company's proposed merger with Wisconsin Energy Corporation.

ITEM NUMBER 3 - None

ITEM NUMBER 4 - None

ITEM NUMBER 5 - None

ITEM NUMBER 6 - See pages 256-257 for detail on the amount of long-term debt obligations incurred and page 121 for the net increase (decrease) in short-term debt (including commercial paper) obligations during 1996. Also, see the Notes to the Financial Statements for additional information on long-term and short-term debt. These securities issuances are within levels authorized by the Minnesota Public Utilities Commission in its Docket No. E,G002/S-95-1021.

ITEM NUMBER 7 - None

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

IMPORTANT CHANGES DURING THE YEAR (Continued)

ITEM NUMBER 8

Classification	1996 Annual Average Base Salary Increase
1) Union	4.0% of base payroll
2) Nonunion non-exempt clerical and technical	4.2% of base payroll
3) Exempt	3.9% of base payroll

ITEM NUMBER 9 - See Note 13 in the Notes to the Financial Statements for a discussion of major contracts, agreements, commitments, legal proceedings, and environmental issues relevant to 1996. While the final impact on pending legal and environmental proceedings at year end is not known, the Company has recorded an accrual representing the best current cost estimate of these proceedings. The following supplementary information is in addition to Note 13:

With respect to the 1993 natural gas explosion on the Company's distribution system in St. Paul, the cost incurred by NSP for this matter is the $1 million insurance deductible, which was accrued in a prior year.

On June 20, 1994, the Company along with other major utilities filed a lawsuit against the United States Department of Energy (DOE) in an attempt to clarify the DOE's obligation to dispose of spent nuclear fuel beginning not later than January 31, 1998. The suit was filed in the U.S. Court of Appeals, Washington, D.C. The primary purpose of the lawsuit was to insure that the Company and its customers receive timely storage and disposal of spent nuclear fuel in accordance with the terms of the Company's contract with the DOE. On July 23, 1996, the U.S. Court of Appeals for the District of Columbia Circuit, affirmed the federal government's obligation. The court unanimously ruled that the Nuclear Waste Policy Act creates an unconditional obligation for the DOE to begin acceptance of spent nuclear fuel by January 31, 1998. The DOE did not seek U.S. Supreme Court review. On January 31, 1997, the Company, along with 30 other electric utilities and 45 state agencies, filed another lawsuit against the DOE requesting authority to withhold payments to the DOE for the permanent disposal program.

With respect to the class action lawsuit related to the Company's lighting efficiency program (LEP), in October 1996 the Hennepin County District Court (the Court) granted, in part, plaintiffs' motion for class action certification in Hamline Park Plaza Partnership, et al v. Northern States Power Company. The Court limited the class to commercial and industrial customers who have participated in the LEP since February 1993. This decision only addresses the procedural issue concerning who may participate in the lawsuit, and does not constitute a determination about the merits of plaintiffs' claims. The Company, which is required to participate in the LEP by virtue of a Minnesota statute, denies all liability with respect to

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IMPORTANT CHANGES DURING THE YEAR (Continued)

plaintiffs' claims. Plaintiffs seek damages in excess of $50,000 for their claims.

ITEM NUMBER 10 - None

ITEM NUMBER 11 - Not applicable

ITEM NUMBER 12 - Not applicable

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3100 Multifoods Tower
33 South Sixth Street
Minneapolis, MN 55402-3795

Telephone 612 332 7000
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Price Waterhouse LLP

REPORT OF INDEPENDENT ACCOUNTANTS

February 3, 1997

To the Shareholders and Board of Directors
of Northern States Power Company (Minnesota)

We have audited the balance sheets of Northern States Power Company, a Minnesota corporation (the "Company") as of December 31, 1996 and 1995, the related statements of income for the years then ended, and the related statements of retained earnings and of cash flows for the year ended December 31, 1996, included on pages 110 through 123.19 of the accompanying Federal Energy Regulatory Commission Form 1. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in the applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than generally accepted accounting principles.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 1996 and 1995, and the results of its operations for the years then ended, and its cash flows for the year ended December 31, 1996, in conformity with the accounting requirements of the Federal Energy Regulatory Commission as set forth in the applicable Uniform System of Accounts and published accounting releases.

This report is intended solely for the information and use of the shareholders, board of directors and management of the Company and for filing with the Federal Energy Regulatory Commission and should not be used for any other purpose.

Price Waterhouse LLP

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200-201	$6,238,307,409	$6,508,697,990
3	Construction Work in Progress (107)	200-201	187,945,885	156,930,471
4	TOTAL UTILITY PLANT (Enter Total of lines 2 and 3)		$6,426,253,294	$6,665,628,461
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	2,899,642,941	3,139,136,901
6	Net Utility Plant (Enter Total of line 4 Less 5)	-	$3,526,610,353	$3,526,491,560
7	Nuclear Fuel (120.1-120.4, 120.6)	202-203	843,918,779	892,484,120
8	(Less) Accum. Prov. for Amort. of Nucl. Assemblies (120.5)	202-203	752,821,108	792,146,298
9	Net Nuclear Fuel (Enter Total of lines 7 Less 8)	-	$91,097,671	$100,337,822
10	Net Utility Plant (Enter Total of lines 6 and 9)	-	$3,617,708,024	$3,626,829,382
11	Utility Plant Adjustments (116)	122		
12	Gas Stored Underground-Noncurrent (117)	-		
13	OTHER PROPERTY AND INVESTMENTS			
14	Nonutility Property (121)	221	37,815,104	37,397,717
15	(Less) Accum. Prov. for Depr. and Amort. (122)	-	11,606,398	13,304,519
16	Investments in Associated Companies (123)	-		
17	Investment in Subsidiary Companies (123.1)	224-225	709,137,937	832,853,308
18	(For Cost of Account 123.1, See Footnote Page 224, Line 42)	-		
19	Noncurrent Portion of Allowances	228-229		
20	Other Investments (124)		18,811,969	34,655,505
21	Special Funds (125-128)	-	203,622,039	260,751,406
22	TOTAL Other Property and Investments (Total of lines 14—17,19—21)		$957,780,651	$1,152,353,417
23	CURRENT AND ACCRUED ASSETS			
24	Cash (131)	-	6,938,578	15,080,641
25	Special Deposits (132-134)	-	369,000	185,000
26	Working Fund (135)	-	306,512	289,923
27	Temporary Cash Investments (136)	-		2,548,362
28	Notes Receivable (141)		3,156,350	3,194,421
29	Customer Accounts Receivable (142)	-	233,830,113	259,333,779
30	Other Accounts Receivable (143)	-	21,410,984	27,499,902
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	-	3,383,976	8,163,963
32	Notes Receivable from Associated Companies (145)	-	51,451,870	39,894,322
33	Accounts Receivable from Assoc. Companies (146)		17,328,330	18,052,224
34	Fuel Stock (151)	227	23,796,377	21,516,095
35	Fuel Stock Expenses Undistributed (152)	227	1,432,267	1,308,399
36	Residuals (Elec) and Extracted Products (153)	227		
37	Plant Materials and Operating Supplies (154)	227	92,353,122	98,303,893
38	Merchandise (155)	227		1,482,582
39	Other Materials and Supplies (156)	227	396,202	472,717
40	Nuclear Materials Held for Sale (157)	202-203/227		
41	Allowances (158.1 and 158.2)	228-229		
42	(Less) Noncurrent Portion of Allowances	228-229		
43	Stores Expense Undistributed (163)	-	(32,988)	346,948
44	Gas Stored Underground-Current (164.1)	-	8,688,317	10,423,938
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)	-	3,334,909	3,985,223
46	Prepayments (165)	-	12,889,714	18,398,189
47	Advances for Gas (166-167)	-		
48	Interest and Dividends Receivable (171)	-		
49	Rents Receivable (172)	-	181,159	169,915
50	Accrued Utility Revenues (173)	-	93,984,947	126,292,633
51	Miscellaneous Current and Accrued Assets (174)		157,143	40,784
52	TOTAL Current and Accrued Assets (Enter Total of lines 24 thru 51)		$568,588,930	$640,655,927

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
53	DEFERRED DEBITS			
54	Unamortized Debt Expenses (181)	-	$7,716,696	$6,619,367
55	Extraordinary Property Losses (182.1)	230		
56	Unrecovered Plant and Regulatory Study Costs (182.2)	230		
57	Other Regulatory Assets (182.3)	232	284,795,036	266,765,801
58	Prelim. Survey and Investigation Charges (Electric) (183)	-	(17,096)	(17,096)
59	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)	-		
60	Clearing Accounts (184)	-	1,645,412	1,070,936
61	Temporary Facilities (185)	-		2,850
62	Miscellaneous Deferred Debits (186)	233	86,719,733	102,510,813
63	Def. Losses from Disposition of Utility Plt. (187)	-		
64	Research, Devel. and Demonstration Expend. (188)	352-353		
65	Unamortized Loss on Reacquired Debt (189)	-	53,460,217	50,140,264
66	Accumulated Deferred Income Taxes (190)	234	332,819,924	351,752,524
67	Unrecovered Purchased Gas Costs (191)	-	9,125,873	5,977,669
68	TOTAL Deferred Debits (Enter Total of lines 54 thru 67)		$776,265,795	$784,823,128
69	TOTAL Assets and other Debits (Enter Total of lines 10,11,12, 22,52,and 68)		$5,920,343,400	$6,204,661,854

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

COMPARATIVE BALANCE SHEET (LIABILITES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	$170,439,834	$172,659,279
3	Preferred Stock Issued (204)	250-251	240,000,000	240,000,000
4	Capital Stock Subscribed (202, 205)	252		
5	Stock Liability for Conversion (203, 206)	252		
6	Premium on Capital Stock (207)	252	602,401,048	642,710,278
7	Other Paid-in Capital (208-211)	253	(3,352,993)	(3,579,611)
8	Installments Received on Capital Stock (212)	252	515,173	80,731
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254		
11	Retained Earnings (215, 215.1, 216)	118-119	991,220,056	1,037,617,239
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	272,217,302	299,884,042
13	(Less) Reacquired Capital Stock (217)	250-251	10,656,748	19,091,577
14	TOTAL Proprietary Capital (Enter Total of Lines 2 thru 13)	-	$2,262,783,672	$2,370,280,381
15	LONG-TERM DEBT			
16	Bonds (221)	256-257	1,093,600,000	1,083,500,000
17	(Less) Reacquired Bonds (222)	256-257		
18	Advances from Associated Companies (223)	256-257		
19	Other Long-Term Debt (224)	256-257	265,742,932	270,624,674
20	Unamortized Premium on Long-Term Debt (225)	-	119,428	101,920
21	(Less) Unamortized Discount on Long-Term Debt-Debit (226)	-	4,868,874	4,376,537
22	TOTAL Long-Term Debt (Enter Total of Lines 16 thru 21)	-	$1,354,593,486	$1,349,850,057
23	OTHER NONCURRENT LIABILITIES			
24	Obligations Under Capital Leases-Noncurrent (227)	-		
25	Accumulated Provision for Property Insurance (228.1)	-		
26	Accumulated Provision for Injuries and Damages (228.2)	-		
27	Accumulated Provision for Pensions and Benefits (228.3)	-	46,473,923	61,336,583
28	Accumulated Miscellaneous Operating Provisions (228.4)	-	36,954,457	34,255,752
29	Accumulated Provision for Rate Refunds (229)	-		
30	TOTAL OTHER Noncurrent Liabilities (Enter Total of lines 24 thru 29)		$83,428,380	$95,592,335
31	CURRENT AND ACCRUED LIABILITIES			
32	Notes Payable (231)	-	216,177,070	361,930,878
33	Accounts Payable (232)	-	225,655,575	229,321,286
34	Notes Payable to Associated Companies (233)	-		
35	Account Payable to Associated Companies (234)	-	9,253,742	7,577,036
36	Customer Deposits (235)	-	1,075,823	886,125
37	Taxes Accrued (236)	262-263	193,072,771	196,367,874
38	Interest Accrued (237)	-	25,650,820	25,130,377
39	Dividends Declared (238)	-	48,875,424	50,408,682
40	Matured Long-Term Debt (239)	-		
41	Matured Interests (240)	-		
42	Tax Collections Payable (241)	-	12,296,398	9,811,693
43	Miscellaneous Current and Accrued Liabilities (242)		13,341,104	10,331,478
44	Obligations Under Capital Leases-Current (243)			
45	TOTAL Current and Accrued Liabilities(Enter Total of lines 32 thru 44)		$745,398,727	$891,765,429

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance End of Year (d)
46	DEFERRED CREDITS			
47	Customer Advances for Construction (252)		$1,325,920	$1,2[illegible]8,741
48	Accumulated Deferred Investment Tax Credits (255)	266-267	138,239,554	127,729,273
49	Deferred Gains from Disposition of Utility Plant (256)			
50	Other Deferred Credits (253)	269	72,840,771	54,687,817
51	Other Regulatory Liabilities (254)	278	224,202,399	283,202,641
52	Unamortized Gain on Reacquired Debt (257)	269		
53	Accumulated Deferred Income Taxes (281-283)	272-277	1,037,530,491	1,[illegible],345,180
54	TOTAL Deferred Credits (Enter Total of Lines 47 thru 53)		$1,474,139,135	$1,[illegible],173,652
55				
56				
57				
58				
59				
60				
61				
62				
63				
64				
65				
66				
67				
68	TOTAL Liabilities and Other Credits (Enter Total of Lines 14, 22, 30, 45 and 54)		$5,920,343,400	$6,204,661,854

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another Utility column (i,k,m,o) in a similar manner to a utility department. Spread the amount(s) over lines 02 thru 24 as appropriate. Include these amounts in columns (c) and (d) totals.

2. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

3. Report data for lines 7,9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

4. Use pages 122-123 for important notes regarding the statement of income or any account thereof.

5. 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 a material refund to the utility with respect to power or gas purchases. State for each year affected 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 and gas purchases.

6. Give concise explanations concerning significant amounts of any refunds made or received duing the year.

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301	$2,433,169,873	$2,355,753,711
3	Operating Expenses			
4	Operation Expenses (401)	320-323	1,375,933,701	1,337,430,520
5	Maintenance Expenses (402)	320-323	132,460,733	133,195,753
6	Depreciation Expense (403)	336-337	261,993,777	250,493,000
7	Amort. & Depl. of Utility Plant (404-405)	336-337	7,430,600	5,400,075
8	Amort. of Utility Plant Acq. Adj. (406)	336-337		
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)			
10	Amort. of Conversion Expenses (407)			
11	Regulatory Debits (407.3)			(1,174)
12	(Less) Regulatory Credits (407.4)		92,931	92,930
13	Taxes Other Than Income Taxes (408.1)	262-263	216,944,133	223,486,465
14	Income Taxes - Federal (409.1)	262-263	134,960,276	118,653,052
15	- Other (409.1)	262-263	35,701,071	28,669,119
16	Provision for Deferred Income Taxes (410.1)	234,272-277	70,804,992	70,651,736
17	(Less) Provision for Deferred Income Taxes - Cr. (411.1)	234,272-277	98,169,339	88,648,906
18	Investment Tax Credit Adj. - Net (411.4)	266	(8,133,435)	(7,871,001)
19	(Less) Gains from Disp. of Utility Plant (411.6)			
20	Losses from Disp. of Utility Plant (411.7)			
21	(Less) Gains from Disposition of Allowances (411.8)			
22	Losses from Disposition of Allowances (411.9)			
23	TOTAL Utility Operating Expenses (Enter Total of Lines 4 thru 22)		$2,129,833,578	$2,071,365,709
24	Net Utility Operating Income (Enter Total of line 2 less 23) (Carry forward to page 117, line 25)		$303,336,295	$284,388,002

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

STATEMENT OF INCOME FOR THE YEAR (Continued)

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.

7. f any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be included or pages 122-123.

8. Enter on pages 122-123 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 approximate dollar effect of such changes.

9. Explain in a footnote if the previous year's figures are different from that reported in prior reports.

10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 23, and report the information in the blank space on pages 122-123 or in a footnote.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year (e)	Previous Year (f)	Current Year (g)	Previous Year (h)	Current Year (i)	Previous Year (j)	Line No.
						1
$2,006,032,146	$2,019,111,010	$426,486,661	$335,989,244	$651,066	$653,457	2
						3
1,039,191,924	1,083,438,487	336,741,777	253,992,033			4
125,717,036	127,020,327	6,743,697	6,175,426			5
242,169,596	232,390,099	19,824,181	18,102,901			6
6,726,902	5,022,757	703,698	377,318			7
						8
						9
						10
	(1,174)					11
		92,931	92,930			12
193,287,211	201,623,970	23,656,922	21,862,495			13
122,977,527	108,097,865	11,982,749	10,555,187			14
32,531,272	26,118,760	3,169,799	2,550,359			15
65,757,385	64,426,366	5,047,607	6,225,370			16
91,729,826	82,974,583	6,439,513	5,674,323			17
(7,706,024)	(7,424,665)	(427,411)	(446,336)			18
						19
						20
						21
						22
$1,728,923,003	$1,757,738,209	$400,910,575	$313,627,500			23
$277,109,143	$261,372,801	$25,576,086	22,361,744	$651,066	$653,457	24

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	OTHER UTILITY		OTHER UTILITY		OTHER UTILITY	
	Current Year (k)	Previous Year (l)	Current Year (m)	Previous Year (n)	Current Year (o)	Previous Year (p)
1	[redacted]					
2						
3	[redacted]					
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24	0	0				

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
25	Net Utility Operating Income (Carried forward from page 114)	--	$303,336,295	$284,388,002
26	Other Income and Deductions			
27	Other Income			
28	Nonutility Operating Income			
29	Revenues From Merchandising, Jobbing and Contract Work (415)		12,321,831	7,097,807
30	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		11,927,796	6,976,829
31	Revenues From Nonutility Operations (417)		20,445,250	20,322,042
32	(Less) Expenses of Nonutility Operations (417.1)		17,558,813	15,189,922
33	Nonoperating Rental Income (418)		(42,974)	(43,769)
34	Equity in Earnings of Subsidiary Companies (418.1)	119	56,706,360	72,934,365
35	Interest and Dividend Income (419)		7,362,865	11,202,814
36	Allowance for Other Funds Used During Construction (419.1)		7,225,872	6,346,144
37	Miscellaneous Nonoperating Income (421)		1,294,110	(1,649,747)
38	Gain on Disposition of Property (421.1)		172,676	204,692
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		$75,999,381	$94,247,597
40	Other Income Deductions			
41	Loss on Disposition of Property (421.2)		349,666	9,717
42	Miscellaneous Amortization (425)	340	14,832	29,593
43	Miscellaneous Income Deductions (426.1-426.5)	340	6,595,422	6,269,327
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)		$6,959,920	$6,308,637
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)	262-263	1,155,929	902,403
47	Income Taxes - Federal (409.2)	262-263	1,713,767	1,429,456
48	Income Taxes - Other (409.2)	262-263	481,572	150,565
49	Provision for Deferred Inc. Taxes (410.2)	234,272-277	1,434,037	798,787
50	(Less) Provision for Deferred Income Taxes - Cr. (411.2)	234,272-277	503,376	720,777
51	Investment Tax Credit Adj. - Net (411.5)		(614,470)	(528,031)
52	(Less) Investment Tax Credits (420)			
53	TOTAL Taxes on Other Income and Deduct. (Total of 46 thru 52)		$3,667,459	$2,032,403
54	Net Other Income and Deductions (Enter Total of lines 39, 44, 53)		$65,372,002	$85,906,557
55	Interest Charges			
56	Interest on Long-Term Debt (427)		83,866,132	85,776,934
57	Amort. of Debt Disc. and Expense (428)		1,589,666	1,611,480
58	Amortization of Loss on Reacquired Debt (428.1)		3,319,953	3,041,941
59	(Less) Amort. of Premium on Debt - Credit (429)		17,508	17,508
60	(Less) Amortization of Gain on Reacquired Debt - Credit (429.1)			
61	Interest on Debt to Assoc. Companies (430)	340		14,396
62	Other Interest Expense (431)	340	16,247,364	14,021,499
63	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		10,836,352	9,949,362
64	Net Interest Charges (Enter Total of lines 56 thru 63)		$94,169,255	$94,499,380
65	Income Before Extraordinary Items (Total of lines 25, 54 and 64)		$274,539,042	$275,795,179
66	Extraordinary Items			
67	Extraordinary Income (434)			
68	(Less) Extraordinary Deductions (435)			
69	Net Extraordinary Items (Enter Total of line 67 less line 68)			
70	Income Taxes-Federal and Other (409.3)	262-263		
71	Extraordinary Items After Taxes (Enter Total of line 69 less line 70)			
72	Net Income (Enter Total of lines 65 and 71)		$274,539,042	$275,795,179

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the the year.

2. 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).

3. State the purpose and amount of each reservation or appropriation of retained earnings.

4. 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.

5. Show dividends for each class and series of capital stock.

6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.

7. 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.

8. 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)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance - Beginning of Year		$991,142,433
2	Changes (Identify by prescribed retained earnings accounts)		
3	Adjustments to Retained Earnings (Account 439)		
4	Credit:		
5	Credit:		
6	Credit:		
7	Credit:		
8	Credit:		
9	TOTAL Credits to Retained Earnings (Acc. 439) (Total of lines 4 thru 8)		
10	Debit: Loss on stock reacquired and issued under Long-Term Incentive Plan		(22,688)
11	Debit:		
12	Debit:		
13	Debit:		
14	Debit:		
15	TOTAL Debits to Retained Earnings (Acc. 439) (Total of lines 10 thru 14)		($22,688)
16	Balance Transferred from Income (Account 433 less Account 418.1)		217,832,682
17	Appropriations of Retained Earnings (Account 436)		
18			
19			
20			
21			
22	TOTAL Appropriations of Retained Earnings (Acc. 436) (Total of lines 18 thru 21)		
23	Dividends Declared - Preferred Stock (Account 437)		
24	All Series		(12,245,501)
25			
26			
27			
28			
29	TOTAL Dividends Declared - Preferred Stock (Acct. 437) (Total of lines 24 thru 28)		(12,245,501)
30	Dividends Declared - Common Stock (Account 438)		
31			(187,521,470)
32			
33			
34			
35			
36	TOTAL Dividends Declared - Common Stock (Acct. 438) (Total of lines 31 thru 35)		($187,521,470)
37	Transfers from Acct. 216.1, Unappropriated Undistributed Subsidiary Earnings		28,354,160
38	Balance - End of Year (Total of lines 01, 09, 15, 16, 22, 29, 36, and 37)		$1,037,539,616

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

STATEMENT OF RETAINED EARNINGS FOR THE YEAR (Continued)

Line No.	Item (a)	Amount (b)
	APPROPRIATED RETAINED EARNINGS (Account 215) State balance and purpose of each appropriated retained earnings amount at end of year and give accounting entries for any applications of appropriated retained earnings during the year.	
39		
40		
41		
42		
43		
44		
45	TOTAL Appropriated Retained Earnings (Account 215)	
	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE,FEDERAL (Account 215.1) State below the total amount set aside through appropriations of retained earnings, as of the end of the year, in compliance with the provisions of Federally granted hydroelectric project licenses held by the respondent. If any reductions or changes other than the normal annual credits hereto have been made during the year, explain such items in a footnote.	
46	TOTAL Appropriated Retained Earnings - Amortization Reserve, Federal (Account 215.1)	77,623
47	TOTAL Appropriated Retained Earnings (Account 215, 215.1) (Enter total of lines 45 and 46)	$77,623
48	TOTAL Retained Earnings (Account 215, 215.1, 216) (Enter total of lines 38 and 47)	$1,037,617,239
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (ACCOUNT 216.1)	
49	Balance - Beginning of Year (Debit or Credit)	272,217,302
50	Equity in Earnings for Year (Credit) (Account 418.1)	56,706,360
51	(Less) Dividends Received (Debit)	28,354,160
52	Other Changes (Explain)	* (685,460)
53	Balance - End of Year (Total of Lines 49 Thru 52)	$299,884,042

< Page 119 Line 52 Column b >

Transfer From/(To) Appropriated Retained Earnings by Subsidiary.

Northern States Power Company (Wisconsin), a wholly owned subsidiary of the Company, transferred a portion of its Unappropriated Retained Earnings to Appropriated Retained Earnings. The impact on the Company is a reduction of Unappropriated Undistributed Subsidiary Earnings.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

STATEMENT OF CASH FLOWS

1. If the notes to the cash flow statement in the respondents annual stockholders report are applicable to this statement, such notes should be included in pages 122-123. Information about noncash investing and financing activities should be provided on pages 122-123. Provide also on pages 122-123 a reconciliation between "Cash and Cash Equivalents at End of Year" with related amounts on the balance sheet.
2. Under "Other" specify significant amounts and group others.
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 on pages 122-123 the amount of interest paid (net of amounts capitalized) and income taxes paid.

Line No.	Description (See Instruction No. 5 for Explanation of Codes) (a)	Amounts (b)
1	Net Cash Flow from Operating Activities:	
2	Net Income (Line 72(c) on page 117)	$274,539,042
3	Noncash Charges (Credits) to Income:	
4	Depreciation and Depletion	276,426,266
5	Amortization of (Specify)	
6	Nuclear Fuel	45,773,602
7	Deferred Debits/Credits	8,926,765
8	Deferred Income Taxes (Net)	(26,433,686)
9	Investment Tax Credit Adjustment (Net)	(8,747,905)
10	Net (Increase) Decrease in Receivables	(27,563,318)
11	Net (Increase) Decrease in Inventory	(7,871,589)
12	Net (Increase) Decrease in Allowances Inventory	
13	Net Increase (Decrease) in Payables and Accrued Expenses	19,936,104
14	Net (Increase) Decrease in Other Regulatory Assets	13,994,580
15	Net Increase (Decrease) in Other Regulatory Liabilities	42,366,170
16	(Less) Allowance for Other Funds Used During Construction	7,225,872
17	(Less) Undistributed Earnings from Subsidiary Companies	28,352,200
18	Other:(Increase) Decrease in Accrued Utility Revenues	(32,307,686)
19	Miscellaneous Changes in Working Capital	(10,685,858)
20	Changes in Other Assets and Liabilities	(32,003,852)
21		
22	Net Cash Provided by (Used in) Operating Activities (Total of lines 2 thru 21)	$500,770,563
23		
24	Cash Flows from Investment Activities:	
25	Construction and Acquisition of Plant (Including Land):	
26	Gross Additions to Utility Plant (less nuclear fuel)	(250,511,379)
27	Gross Additions to Nuclear Fuel	(48,565,341)
28	Gross Additions to Common Utility Plant	(30,054,262)
29	Gross Additions to Nonutility Plant	(835,172)
30	(Less) Allowance for Other Funds Used During Construction	7,225,872
31	Other:Proceeds from the sale of nonutility property	841,409
32		
33		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	($321,898,873)
35		
36	Acquisition of Other Noncurrent Assets (d) External Decommissioning Fund	(40,496,783)
37	Proceeds from Disposal of Noncurrent Assets (d)	
38		
39	Investments in and Advances to Assoc. and Subsidiary Companies	(96,642,953)
40	Contributions and Advances from Assoc. and Subsidiary Companies	
41	Disposition of Investments in (and Advances to)	
42	Associated and Subsidiary Companies	
43		
44	Purchase of Investment Securities (a)	
45	Proceeds from Sales of Investment Securities (a)	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

STATEMENT OF CASH FLOWS (Continued)

4. Investing Activities
Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed on pages 122-123.
Do not include on this statement the dollar amount of leases capitalized per US of A General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost on pages 122-123.

5. Codes used:
(a) Net proceeds or payments.
(b) Bonds, debentures and other long term debt.
(c) Include commercial paper.
(d) Identify separately such items as investments, fixed assets, intangibles, etc.

6. Enter on pages 122-123 clarifications and explanations.

Line No.	Description (See Instruction No. 5 for Explanation of Codes) (a)	Amounts (b)
46	Loans Made or Purchased	
47	Collections on Loans	
48		
49	Net (Increase) Decrease in Receivables	12,151,870
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: Net Decrease in Construction Payables	(3,598,209)
54	Miscellaneous Other Investing Activities	(15,843,536)
55		
56	Net Cash Provided by (Used in) Investing Activities	
57	(Total of lines 34 thru 55)	($466,328,484)
58		
59	Cash Flows from Financing Activities:	
60	Proceeds from Issuance of:	
61	Long - Term Debt (b)	
62	Preferred Stock	
63	Common Stock	41,724,615
64	Other:	
65		
66	Net Increase in Short - Term Debt (c)	
67	Other:	
68		
69		
70	Cash Provided by Outside Sources (Total of lines 61 thru 69)	$41,724,615
71		
72	Payments for Retirement of:	
73	Long - term Debt (b)	(12,996,363)
74	Preferred Stock	
75	Common Stock	
76	Other:	
77		
78	Net Decrease in Short-Term Debt (c)	145,753,808
79		
80	Dividends on Preferred Stock	(12,245,502)
81	Dividends on Common Stock	(185,988,212)
82	Net Cash provided by (Used in) Financing Activities	
83	(Total of lines 70 thru 81)	($23,751,654)
84		
85	Net Increase (Decrease) in Cash and Cash Equivalents	
86	(Total of lines 22, 57, and 83)	$10,690,425
87		
88	Cash and Cash Equivalents at Beginning of Year	6,938,578
89		
90	Cash and Cash Equivalents at End of Year	17,629,003

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 Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.

5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.

6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK

SEE PAGE 123 FOR REQUIRED INFORMATION

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

System of Accounts - The Company maintains the accounting records in accordance with either the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) or those prescribed by state regulatory commissions, whose systems 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 applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than generally accepted accounting principles. As required by the FERC, the Company accounts for its investment in majority-owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues, and expenses of these subsidiaries, as required by generally accepted accounting principles. In addition, as required by the FERC, the Company has classified $351,753,000 of deferred income tax assets as deferred debits rather than as current assets (as to the current portion) and as an offset to deferred income tax liabilities in deferred credits (as to the noncurrent portion), as required by generally accepted accounting principles. If generally accepted accounting principles were followed, net utility plant would be increased by $711,051,000, current assets by $156,567,000, other long-term assets would be decreased by $435,379,000, current liabilities would be increased by $344,635,000, and long-term debt and other long-term liabilities by $81,535,000 as of Dec. 31, 1996. Furthermore, operating revenues would be increased by $221,036,000, operating expenses by $158,328,000, cash provided by operating activities by $43,693,000, cash used for investing activities by $181,672,000, cash provided by financing activities by $149,612,000 and other income and deductions would be decreased by $26,178,000 for the year ended Dec. 31, 1996. Accounting for the investments in majority-owned subsidiaries on the equity method and classifying certain deferred income tax assets as deferred debits, rather than in accordance with generally accepted accounting principles, have no effect on net income and no material effect on retained earnings.

Subsidiaries - Consistent with the FERC reporting requirements, the Company carries its investment in its subsidiaries at cost plus equity in undistributed earnings since acquisition. The net investment in such subsidiaries is included in Other Property and Investments, and the results of subsidiaries' operations are included in Other Income and Deductions. The Company and its subsidiaries are referred to herein as NSP.

Revenues - Revenues are recognized based on services provided to customers each month. Because utility customer meters are read and billed on a cycle basis, unbilled revenues (and related energy costs) are estimated and recorded for services provided from the monthly meter-reading dates to month-end.

The Company's rate schedules, applicable to substantially all of its utility customers, include cost-of-energy and resource adjustment clauses, under which rates are adjusted to reflect changes in average costs of fuels, purchased power, gas purchased for resale, and in Minnesota, electric and gas conservation and energy management program costs.

Utility Plant and Retirements - Utility plant is stated at original cost. The Company's utility plant and construction expenditures consist of approximately 91% electric and 9% gas. The cost of additions to utility plant includes direct labor and materials, contracted work, allocable overheads, and allowance for funds used during construction. The cost of units of property retired, plus net removal cost, is charged to the accumulated provision for depreciation and amortization. Maintenance and replacement of items determined to be less than units of property are charged to operating expenses.

Allowance for Funds Used During Construction (AFC) - AFC, a non-cash item, is computed by applying a composite pretax rate, representing the cost of capital used to finance construction, to qualified Construction Work in Progress (CWIP). The rates were 5.5% in 1996 and 6.0% in 1995. The amount of AFC capitalized as a construction cost in CWIP is credited to other income (for equity capital) and interest charges (for debt capital). AFC amounts capitalized in CWIP are included in utility rate base for establishing utility service rates. In addition to construction-related amounts, AFC is also recorded to reflect returns on capital used to finance conservation programs.

Depreciation - For financial reporting purposes, depreciation is computed by applying the straight-line method over the estimated useful lives of various property classes. The Company files with the Minnesota Public Utilities Commission (MPUC) an annual review of remaining lives for electric and gas production properties. The most recent studies, as approved by the MPUC, recommended immaterial decreases in annual depreciation accruals for 1996 and 1995.

Every five years, the Company also must file an average service life filing for transmission, distribution and general properties. The most recent filings approved by the MPUC were in 1996 for computer software, in 1994 for general plant and in 1993 for all other facilities. Depreciation provisions, as a percentage of the average balance of depreciable utility property in service, were 3.73 percent in 1996 and 3.70 percent in 1995.

Decommissioning - As discussed in Note 12, the Company currently is recording the future costs of decommissioning the Company's nuclear generating plants through annual depreciation accruals. The provision for the estimated decommissioning costs has been calculated using an annuity approach designed to provide for full expense accrual (with full rate recovery) of the future decommissioning costs, including decontamination and removal, over the estimated operating lives of the Company's nuclear plants. The Financial Accounting Standards Board (FASB) has proposed new accounting standards that would require the full accrual of nuclear plant decommissioning and certain other site exit obligations beginning as soon as 1998. (See Note 12 for more discussion of this proposed standard.)

Nuclear Fuel Expense - The original cost of nuclear fuel is amortized to fuel expense based on energy expended. Nuclear fuel expense also includes assessments from the U.S. Department of Energy (DOE) for costs of future fuel disposal and DOE facility decommissioning, as discussed in Note 12.

Environmental Costs - Accruals for environmental costs are recognized when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Costs are charged to expense or deferred as a regulatory asset based on expected recovery in future rates, if they relate to the remediation of conditions caused by past operations, or if they are not expected to mitigate or prevent contamination from future operations. Where environmental expenditures relate to facilities currently in use, such as pollution control equipment, the costs may be capitalized and depreciated over the future service periods. Estimated remediation costs are recorded at undiscounted amounts, independent of any insurance or rate recovery, based on prior experience, assessments and current technology. Accrued obligations are regularly adjusted as environmental assessments and estimates are revised, and remediation efforts proceed. For sites where the Company has been designated as one of several potentially responsible parties, the amount accrued represents the Company's estimated share of the cost. The Company intends to treat any future costs incurred related to decommissioning and restoration of its non-nuclear power plants and substation sites, where operation may extend indefinitely, as a capitalized removal cost of retirement in utility plant. Depreciation expense levels currently recovered in rates include a provision for an estimate of removal costs (based on historical experience).

Income Taxes - The Company records income taxes in accordance with Statement of Financial Accounting Standards (SFAS) No. 109—Accounting for Income Taxes. Under the liability method required by SFAS No. 109, income taxes are deferred for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by law to be in effect when the temporary differences reverse. Due to the effects of regulation, current income tax expense is provided for the reversal of some temporary differences previously accounted for by the flow-through method. Also, regulation has created certain regulatory assets and liabilities related to income taxes, as summarized on pages 232.1 and 278. NSP's policy for income taxes related to international operations is discussed in Note 7.

Investment tax credits were deferred and are being amortized over the estimated lives of the related property.

Inventories - Materials and supplies inventories are carried at average cost.

Foreign Currency Translation - The local currencies are generally the functional currency of foreign operations of the Company's subsidiary, NRG Energy, Inc. (NRG). Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. Income, expense and cash flows are translated at weighted-average rates of exchange for the period. The resulting currency translation adjustments are accumulated and reflected in the Company's Investment in Subsidiary Companies.

Exchange gains and losses that result from foreign currency transactions (e.g. converting cash distributions made in one currency to another) are included in NRG's results of operations as a component of Equity in Earnings of Subsidiary Companies. Through Dec. 31, 1996, NSP's translation gains or losses from foreign currency transactions that have occurred since the respective foreign investment dates have been immaterial.

Derivative Financial Instruments - As discussed in Note 9, a derivative instrument used by the Company is interest rate swaps that convert fixed rate debt to variable rate debt. The cost or benefit of the interest rate swap agreements is recorded as a component of interest expense. In addition, the Company's subsidiary, NRG has entered into currency hedging transactions through the use of forward foreign currency exchange agreements. NSP's policy is to hedge foreign currency denominated investments as they are made, where appropriate hedging instruments are available, to preserve their U.S. dollar value. Gains and losses on these agreements offset the effect of foreign currency exchange rate fluctuations on the valuation of the investments underlying the hedges. Investments in Subsidiary Companies includes hedging gains and losses, net of income tax effects, and other currency translation adjustments. NRG is not hedging currency translation adjustments related to future operating results. NSP does not speculate in foreign currencies. A third derivative arrangement is the use of natural gas futures contracts by the Company's subsidiary, Cenerprise, Inc. (Cenerprise) to manage the risk of gas price fluctuations. The cost or benefit of natural gas futures contracts is recorded when related sales commitments are fulfilled as a component of Equity in Earnings of Subsidiary Companies. NSP does not speculate in natural gas futures. None of these three derivative financial instruments is reflected on the Company's balance sheet.

Use of Estimates - In recording transactions and balances resulting from business operations, NSP uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives, tax provisions, uncollectible accounts, environmental costs, unbilled revenues and actuarially determined benefit costs. As better information becomes available (or actual amounts are determinable), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates. Recent changes in interest rates have resulted in changes to actuarial assumptions used in the benefit cost calculations for postretirement benefits, as discussed in Note 8. Also, the depreciable lives of certain plant assets are reviewed and, if appropriate, revised periodically, as discussed previously.

Investments in Marketable Securities - The Company has three types of investments in marketable securities. Two of these types, cash equivalents and short-term investments, are intended to be held to maturity and are carried at cost which approximates market value. The Company considers investments in certain debt instruments (primarily commercial paper) with an original maturity to the Company of three months or less at the time of purchase to be cash equivalents. The third type, investments in external decommissioning trust funds, are considered available for sale and are carried at market value. Unrealized gains or losses resulting from changes in market values of these decommissioning investments are deferred as a regulatory liability or asset, respectively, due to the effects of regulation. The Company anticipates offsetting such unrealized gains or losses, when realized, against decommissioning costs in future ratemaking.

Regulatory Deferrals - As a regulated utility, the Company accounts for certain income and expense items under the provisions of SFAS No. 71 - Accounting for the Effects of Regulation. In doing so, certain costs that would otherwise be charged to expense are deferred as regulatory assets based on expected recovery from customers in future rates. Likewise, certain credits that would otherwise be reflected as income are deferred as regulatory liabilities based on expected flowback to customers in future rates. Management's expected recovery of deferred costs and expected flowback of deferred credits are generally based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistent with ratemaking treatment as established by regulators. Pages 232 and 278 describe in more detail the nature and amounts of these regulatory deferrals.

Stock-Based Employee Compensation - The Company has several stock-based compensation plans, as described in Note 4. Under the intrinsic-value-based method of accounting followed by the Company, no compensation expense is recorded for stock options because there is no difference between the market price and purchase price at the grant date, which is the measurement date for determining compensation expense. The Company does, however, record compensation expense for stock that is awarded to certain employees, but held by the Company until the restrictions lapse or the stock is forfeited. Effective for 1996, the FASB issued a new accounting standard, SFAS No. 123---Accounting for Stock-Based Compensation, which provides an optional accounting method for compensation from stock option and other stock award programs. The Company did not elect the new optional accounting method. If the provisions of the optional method had been adopted as of the beginning of 1995, the effect on net income and earnings per share for 1996 and 1995 would have been immaterial.

Supplemental Cash Flow Disclosures - During 1996, the Company made cash payments of $89,797,587 for interest (net of amounts capitalized) and $151,008,503 for income taxes. Cash and cash equivalents consist of cash ($15,080,641 - Account 131) and temporary cash investments ($2,548,362 - Account 136).

2. INVESTMENTS ACCOUNTED FOR BY EQUITY METHOD

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

Name	Geographic Area	Economic Interest
The Company's Wisconsin subsidiary (the Wisconsin Company)	U.S.A.	100%
NRG Energy, Inc.	U.S.A.	100%
Viking Gas Transmission Company	U.S.A.	100%
Cenerprise, Inc.	U.S.A.	100%
Eloigne Company	U.S.A.	100%
United Power & Land	U.S.A.	100%
First Midwest Auto Park, Inc.	U.S.A.	100%
Cormorant Corporation	U.S.A.	100%
Seren Innovations, Inc.	U.S.A.	100%

In addition, several of these wholly owned subsidiaries have equity investments in various international and domestic energy projects and domestic affordable housing and real estate projects. The equity method of accounting is applied to such investments in affiliates, which include joint ventures and partnerships, because the ownership structure prevents the Company from exercising a controlling influence over operating and financial policies of the projects. The total investment by the Company's subsidiaries in these equity-method projects as of Dec. 31, 1996 was approximately $410 million, including $295 million for projects outside the United States. Earnings from equity interests in these subsidiary investments were $32.5 million in 1996.

Summarized Financial Information of Unconsolidated Investees - Summarized financial information for all equity-method subsidiaries and projects, including interests owned by the Company and other parties, was as follows (for the years ended and as of Dec. 31):

Financial Position (Millions of dollars)

	1996	1995
Current Assets	$ 889.8	$ 958.4
Other Assets	4,618.5	3,616.1
Total Assets	$5,508.3	$4,574.5
Current Liabilities	$ 550.1	$ 453.4
Other Liabilities	3,503.7	2,858.7
Equity	1,454.5	1,262.4
Total Liabilities and Equity	$5,508.3	$4,574.5

Results of Operations (Millions of dollars)

	1996	1995
Operating Revenues	$1,657.3	$1,489.7
Operating Income	$138.6	$252.9
Net Income	$113.2	$202.8

3. CUMULATIVE PREFERRED SECURITIES

At Dec. 31, 1996 and 1995, the Company had authorized 7,000,000 shares of Cumulative Preferred Stock and had 2,400,000 shares outstanding.

The Company has two series of adjustable rate preferred stock. The dividend rates are calculated quarterly and are based on prevailing rates of certain taxable government debt securities indices. At Dec. 31, 1996, the annualized dividend rates were $5.50 for both Series A and Series B.

At Dec. 31, 1996, various preferred stock series were callable at prices per share ranging from $100.00 to $103.75, plus accrued dividends.

On Jan. 31, 1997, NSP issued $200 million in 7.875 percent grantor trust-originated preferred securities that mature in 2037. A portion of the proceeds were used to redeem the Company's $6.80 and $7.00 series of preferred stock in February 1997.

4. COMMON STOCK AND INCENTIVE STOCK PLANS

The Company's common shares have a par value of $2.50 per share. At Dec. 31, 1996 and 1995, 160,000,000 shares were authorized and 69,063,712 and 68,175,934 shares were issued and outstanding, respectively, excluding common stock equivalents.

The Company's Articles of Incorporation and First Mortgage Indenture provide for certain restrictions on the payment of cash dividends on common stock. At Dec. 31, 1996, the Company could have paid, without restrictions, additional cash dividends of more than $1 billion on common stock.

The Company has an Executive Long-Term Incentive Award Stock Plan that permits granting nonqualified stock options and restricted stock. The awards granted in any calendar year cannot exceed one-half of one percent of the number of outstanding shares of NSP common stock at the end of the previous calendar year. When options are exercised, or restricted stock granted, the Company may either issue new shares or purchase market shares. Using the treasury stock method of accounting for outstanding stock options, the weighted average number of shares of common stock outstanding for the calculation of primary earnings per share includes any dilutive effects of stock options and other stock awards as common stock equivalents.

Stock options currently granted may be exercised one year from the date of grant and are exercisable thereafter for up to nine years. The options are forfeited if employment ceases before the one-year vesting term. If employment ceases after the one-year vesting term, options will either be forfeited, or would need to be exercised within three or 36 months, depending on the circumstances. The exercise price of an option is the market price of NSP common stock on the date of grant. The plan, in previous years, granted other types of performance awards, some of which are still outstanding. Most of these performance awards were valued in dollars, but paid in shares based on the market price at the time of payment. Transactions under the various incentive stock programs, with the corresponding weighted average exercise price, were as follows:

Stock Option and Performance Awards

	1996		1995	
(Thousands of shares)	Shares	Average Price	Shares	Average Price
Outstanding Jan. 1	990	$41.97	782	$40.58
Options granted in January	263	$50.94	278	$45.50
Other stock awards				
Options and awards exercised	(105)	$41.98	(64)	$40.26
Options and awards forfeited	(27)	$47.70	(6)	$44.58
Options and awards expired	(4)	$40.00		
Outstanding at Dec. 31	1 117	$43.97	990	$41.97
Exercisable at Dec. 31	870	$41.96	716	$40.60

The following table summarizes information about stock options outstanding at Dec. 31, 1996.

	Range of exercise prices $33.25-40.94	Range of exercise prices $42.19-50.94
Options Outstanding:		
Number outstanding at Dec. 31, 1996	244 501	861 759
Weighted-average remaining contractual life (years)	4.2	7.7
Weighted-average exercise price	$37.22	$45.88
Options Exercisable:		
Number exercisable at Dec. 31, 1996	244 501	614 214
Weighted-average exercise price	$37.22	$43.85

In addition to stock options and performance awards, restricted stock is granted based on a dollar value of the award. The market price on the date of grant is used to determine the number of restricted shares awarded. The stock is held by the Company until the restrictions lapse: 50 percent of the stock will vest one year from the date of the award and the remaining 50 percent vests two years from the date of the award. Dividends on the shares held while the restrictions are in place are reinvested to obtain additional shares, and the restrictions apply to these additional shares. In 1995 and 1996, the Company granted restricted stock awards of about 20,000 shares per year at then-current market prices of NSP stock. Compensation expense related to these awards was immaterial.

5. SHORT-TERM BORROWINGS

As of Dec. 31, 1996 and 1995, the Company had approximately $300.0 million and $265.5 million, respectively, of commercial bank credit lines under commitment fee arrangements. These credit lines make short-term financing available in the form of bank loans, letters of credit and support for commercial paper sales. There were no borrowings against these credit lines at Dec. 31, 1996 and 1995. At Dec. 31, 1996 and 1995, credit lines of $74.9 million and $17.0 million, respectively, primarily were provided by commercial banks to wholly owned subsidiaries of the Company. At Dec. 31, 1996, approximately $3.7 million in loans against these credit lines were outstanding. However, the Company and its subsidiaries had $0.0 million and $20.6 million, respectively, in letters of credit outstanding, which reduced the available credit lines at Dec. 31, 1996 and $1.3 million and $8.3 million, respectively at Dec. 31, 1995.

At Dec. 31, 1996 and 1995, the Company had $361.5 million and $215.6 million, respectively, in short-term commercial paper borrowings outstanding, and $0.4 million and $0.6 million, respectively, in short-term bank loans outstanding. The weighted average interest rates on all short-term borrowings were 5.7 percent as of both Dec. 31, 1996 and Dec. 31, 1995. At Dec. 31, 1996 and 1995, wholly owned subsidiaries of the Company had short-term bank loans outstanding of $6.4 million (weighted average interest rate of 5.5%) and $0.0 million, respectively.

6. LONG-TERM DEBT

Except for minor exclusions, all real and personal property of the Company and the Wisconsin Company is subject to the liens of the first mortgage indentures. Certain other debt securities of NSP are secured by a lien on the related real or personal property.

The annual sinking-fund requirements of the Company's and the Wisconsin Company's First Mortgage Indentures are the amounts necessary to redeem 1 percent of the highest principal amount of each series of first mortgage bonds at any time outstanding, excluding those series issued for pollution control and resource recovery financings, and excluding certain other series totaling $950 million and $40 million, respectively. The Company may, and has, applied property additions in lieu of cash payments on all series as permitted by its First Mortgage Indenture. The Wisconsin Company also may apply property additions in lieu of cash on all series as permitted by its First Mortgage Indenture.

At Dec. 31, 1996, the interest rates on the Company's fixed-rate long-term debt ranged from 5.41% to 7 7/8%.

The Company's First Mortgage Bonds Series due March 1, 2011, and the City of Becker Pollution Control Revenue Bonds Series due March 1, 2019, and Sept. 1, 2019, have variable interest rates, which currently change at various periods up to 270 days, based on prevailing rates for certain commercial paper securities or similar issues. The interest rates applicable to these issues averaged 4.2 percent, 3.6 percent and 3.6 percent, respectively, at Dec. 31, 1996. The 2011 series bonds are redeemable upon seven days notice at the option of the bondholder. The Company also is potentially liable for repayment of the 2019 Series Becker Bonds when the bonds are tendered, which occurs each time the variable interest rates change. The principal amount of all three series of these variable rate bonds outstanding, which totalled $141.6 million at Dec. 31, 1996, represents potential short-term obligations; however, under FERC requirements, these amounts are reported under long-term debt on the balance sheet.

Maturities and sinking-fund requirements on the Company's long-term debt are: 1997, $110,603,000; 1998, $7,720,000; 1999, $205,078,000; 2000, $105,362,000; and 2001, $155,803,000.

7. INCOME TAX EXPENSE

Total income tax expense differs from the amount computed by applying the statutory federal income tax rate to net income before income tax expense. The reasons for the difference are as follows (in thousands):

(Thousands of dollars)	1996	1995
Federal Statutory Rate	35.0%	35.0%
Increases (decreases) in tax from:		
State income taxes, net of federal income tax benefit	5.0%	4.2%
Equity in subsidiary earnings - already net of tax	(4.8%)	(6.4%)
Tax credits recognized	(2.1%)	(2.1%)
Regulatory differences-utility plant items	1.0%	1.1%
Other - net	(0.6%)	(1.0%)
Effective income tax rate	33.5%	30.8%

Equity in Earnings of Subsidiary Companies includes net foreign equity income of $28 million and $32 million in 1996 and 1995, respectively. Except to the extent NSP's earnings from foreign operations are subject to current U.S. income taxes, NSP's management intends to reinvest indefinitely such earnings in its foreign operations. Accordingly, U.S. income taxes and foreign withholding taxes have not been provided on a cumulative amount of unremitted earnings of foreign subsidiaries of approximately $87 million at Dec. 31, 1996. The additional U.S. income tax and foreign withholding tax on the unremitted foreign earnings, if repatriated, would be offset in whole or in part by foreign tax credits. Thus, it is impracticable to estimate the amount of tax that might be payable.

The components of the Company's deferred tax liability at Dec. 31 were as follows (in thousands):

(Thousands of dollars)	1996	1995
Deferred tax liabilities:		
Difference between book and tax bases of property	$ 850,336	$ 852,696
Regulatory assets	84,688	83,126
Tax benefit transfer leases	41,842	56,210
Other	53,479	45,498
Total deferred tax liabilities included in deferred credits	$1,030,345	$1,037,530
Deferred tax assets:		
Difference between book and tax bases of property	$ 151,752	$ 134,899
Regulatory liabilities	82,741	90,395
Deferred investment tax credits	49,903	53,405
Deferred compensation, vacation, and other accrued liabilities not currently deductible	57,978	47,303
Other	9,379	6,818
Total deferred tax assets included in deferred debits	$ 351,753	$ 332,820
Net deferred tax liability	$ 678,592	$ 704,710

8. BENEFIT PLANS AND OTHER POSTRETIREMENT BENEFITS

NSP offers the following benefit plans to its benefit employees, of whom approximately 43 percent are represented by five local labor unions under a collective-bargaining agreement, which expired Dec. 31, 1996, but was extended to April 30, 1997. Management and union representatives have reached a tentative agreement on the terms of a new three-year collective bargaining agreement, subject to approval by the union membership.

Pension Benefits - NSP has a non-contributory, defined benefit pension plan that covers substantially all employees. Benefits are based on a combination of years of service, the employee's highest average pay for 48 consecutive months and Social Security benefits.

It is NSP's policy to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations under applicable employee benefit and tax laws. Plan assets principally consist of common stock of public companies, corporate bonds and U.S. government securities. The funded status of NSP's pension plan as of Dec. 31, including amounts allocable to the Company, is as follows:

(Thousands of dollars)	1996 Total Plan	1996 Co. Portion	1995 Total Plan	1995 Co. Portion
Actuarial present value of benefit obligation:				
Vested	$660,920	$568,370	$686,403	$594,535
Nonvested	147,278	126,916	155,177	135,375
Accumulated benefit obligation	$808,198	$695,286	$841,580	$729,910
Projected benefit obligation	$ 993,821	$ 855,971	$1,039,981	$901,525
Plan assets at fair value	1,634,696	1,423,166	1,456,530	1,272,099
Plan assets in excess of projected benefit obligation	640,875	567,195	416,549	370,574
Unrecognized prior service cost	19,734	16,899	20,805	17,803
Unrecognized net actuarial gain	(651,368)	(573,761)	(452,699)	(400,341)
Unrecognized net transitional asset	(539)	(472)	(615)	(538)
Net pension asset (liability) recorded	$ 8,702	$ 9,861	($15,960)	($12,502)

For ratemaking purposes, the Company's pension costs are determined and recorded under the aggregate-cost method. As required by SFAS No. 87 - Employers' Accounting for Pensions, the difference between the pension costs recorded for ratemaking purposes and the amounts determined under SFAS No. 87 is recorded as a regulatory liability on the balance sheet. Net annual periodic pension cost for the Company includes the following components:

(Thousands of dollars)	1996	1995
Service cost-benefits earned during the period	$24,986	$20,527
Interest cost on projected benefit obligation	61,037	60,410
Actual return on assets	(231,123)	(301,191)
Net amortization and deferral	121,528	209,800
Net periodic pension cost determined under SFAS No. 87	(23,572)	(10,454)
Additional costs recognized due to actions of regulators	23,572	10,454
Net periodic pension cost recognized for financial reporting	$0	$0

The weighted average discount rate used in determining the actuarial present value of the projected obligation was 7.5 percent in 1996 and 7 percent in 1995. The rate of increase in future compensation levels used in determining the actuarial present value of the projected obligation was 5 percent in 1996 and 1995. The assumed long-term rate of return on assets used for cost determinations under SFAS No. 87 was 9 percent for 1996 and 1995. Assumption changes increased the Company's 1996 pension costs (determined under SFAS No. 87) by approximately $10.9 million. Because the Company's pension expense is determined under the aggregate-cost method (not SFAS No. 87) for ratemaking and financial reporting purposes, the effects of regulation prevent the majority of these assumption changes from affecting earnings.

Postretirement Health Care - NSP has a contributory health and welfare benefit plan that provides health care and death benefits to substantially all employees after their retirement. The plan is intended to provide for sharing the costs of retiree health care between the Company and retirees. For employees retiring after Jan. 1, 1994, a six-year cost-sharing strategy was implemented with retirees paying 15 percent of the total cost of health care in 1994, increasing to a total of 40 percent in 1999. In conjunction with the 1993 adoption of SFAS No. 106---Employers' Accounting for Postretirement Benefits Other Than Pensions, the Company elected to amortize on a straight-line basis over 20 years the unrecognized accumulated postretirement benefit obligation (APBO) of $184.7 million for current and future retirees.

Before 1993, NSP funded payments for retiree benefits internally. While NSP generally prefers to continue using internal funding of benefits paid and accrued, significant levels of external funding, including the use of tax-advantaged trusts, have been required by NSP's regulators, as discussed below. Plan assets held in such trusts principally consist of investments in equity mutual funds and cash equivalents. The funded status of the NSP's retiree health care plan as of Dec. 31 is as follows:

(Thousands of dollars)	Dec. 31, 1996 Total Plan	Dec. 31, 1996 Co. Portion	Dec. 31, 1995 Total Plan	Dec. 31, 1995 Co. Portion
APBO:				
Retirees	$144,180	$121,526	$145,763	$122,987
Fully eligible plan participants	23,438	18,699	24,406	20,001
Other active plan participants	101,065	85,375	116,810	98,011
Total APBO	268,683	225,600	286,979	240,999
Plan assets at fair value	15,514	6,521	11,583	5,045
APBO in excess of plan assets	253,169	219,079	275,396	235,954
Unrecognized net actuarial loss	(12,467)	(9,981)	(40,411)	(32,483)
Unrecognized transition obligation	(172,480)	(147,761)	(183,260)	(156,997)
Net benefit liability recorded	$68,222	$61,337	$51,725	$46,474

The assumed health care cost trend rates used in measuring the APBO at Dec. 31, 1996 and 1995 were 9.8 percent and 10.4 percent for those under age 65, and 7.1 percent and 7.3 percent for those age 65 and over, respectively. The assumed cost trend rates are expected to decrease each year until they reach 5.5 percent for both age groups in the year 2004, after which they are assumed to remain constant. A 1 percent increase in the assumed health care cost trend rate for each year would increase the APBO by approximately 14 percent as of Dec. 31, 1996. Service and interest cost components of the net periodic postretirement cost would increase by approximately 17 percent with a similar 1 percent increase in the assumed health care cost trend rate. The assumed discount rate used in determining the APBO was 7.5 percent for Dec. 31, 1996 and 7 percent for Dec. 31, 1995, compounded annually. The assumed long-term rate of return on assets used for cost determinations under SFAS No. 106 was 8 percent for 1996 and 1995. Assumption changes decreased the Company's 1995 costs by approximately $1.5 million and increased the Company's 1996 costs by approximately $1.0 million.

The Company's net annual periodic postretirement benefit cost recorded consists of the following components:

(Thousands of dollars)	1996	1995
Service cost-benefits earned during the year	$ 5,222	$ 4,264
Interest cost (on service cost and APBO)	16,196	16,118
Actual return on assets	(283)	(423)
Amortization of transition obligation	9,236	9,236
Net amortization and deferral	(103)	109
Net periodic postretirement health care cost under SFAS No. 106	30,268	29,304
Costs recognized due to actions of regulators	4,033	4,033
Net periodic postretirement health care cost recognized for ratemaking	$34,301	$33,337

Regulators for NSP's retail and wholesale customers in Minnesota, Wisconsin and North Dakota have allowed full recovery of increased benefit costs under SFAS No. 106, effective in 1993. Increased 1993 accrual costs of approximately $12 million for Minnesota retail customers were amortized over the years 1994 through 1996, consistent with approved rate recovery. External funding was required by Minnesota and Wisconsin retail regulators to the extent it is tax advantaged; funding began for Wisconsin in 1993 and must begin by the next general rate filing for Minnesota. For wholesale ratemaking, the FERC has required external funding for all benefits paid and accrued under SFAS No. 106.

ESOP - NSP has a leveraged Employee Stock Ownership Plan (ESOP) that covers substantially all employees. Employer contributions to this non-contributory, defined contribution plan are generally made to the extent NSP realizes a tax savings on its income statement from dividends paid on certain shares held by the ESOP. Contributions to the ESOP in 1996 and 1995, which represent compensation expense to the Company, were $4,647,000 and $5,059,000, respectively. ESOP contributions have no material effect on Company earnings because the contributions (net of tax) are essentially offset by the tax savings provided by the dividends paid on ESOP shares. Leveraged shares held by the ESOP are allocated to participants when dividends on stock held by the plan are used to repay ESOP loans. NSP's ESOP held 5.9 million and 5.7 million shares of the Company's common stock as of Dec. 31, 1996 and 1995, respectively. An average of 208,288 and 221,066 uncommitted leveraged ESOP shares were excluded from earnings-per-share calculations in 1996 and 1995, respectively. The fair value of the Company's leveraged ESOP shares was approximately the same as cost at Dec. 31, 1996 and 1995.

401(k) - NSP has a contributory, defined contribution Retirement Savings Plan, which complies with section 401(k) of the Internal Revenue Code and covers substantially all employees. Since 1994, NSP has been matching specified amounts of employee contributions to this plan. The Company's matching contributions were $4.0 million in 1996 and $3.0 million in 1995.

9. FINANCIAL INSTRUMENTS

Fair Values - The estimated Dec. 31 fair values of the Company's financial instruments are as follows:

	1996		1995	
(Thousands of dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash, cash equivalents and short-term investments	$15,081	$15,081	$6,939	$6,939
Long-term decommissioning investments	$260,756	$260,756	$203,625	$203,625
Long-term debt	$1,349,850	$1,354,429	$1,354,593	$1,407,943

For cash, cash equivalents and short-term investments, the carrying amount approximates fair value because of the short maturity of those instruments. The fair values of the Company's long-term investments, mainly debt securities, in an external nuclear decommissioning fund, are estimated based on quoted market prices for those or similar investments. The fair value of the Company'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.

Derivatives - The Company has two interest rate swap agreements with notional amounts totalling $300 million. These swaps were entered into in conjunction with first mortgage bonds. As summarized below, these agreements effectively convert the interest costs of these debt issues from fixed to variable rates based on six-month London Interbank Offered Rates (LIBOR), with the rates changing semiannually.

Series	Notional Amount (millions of dollars)	Term of Swap Agreement	Net Effective Interest Cost at Dec. 31, 1996
5 7/8% Series due Oct. 1, 1997	$100	Maturity	5.73%
5 1/2% Series due Feb. 1, 1999	$200	Maturity	5.34%

In addition, the Company's Wisconsin subsidiary has an interest rate swap agreement in the notional amount of $20 million until March 1, 1998 related to its $110 million 7 1/4% first mortgage bond, Series due March 1, 2023. The net effective cost of this debt, including the swap, was 7.89% at Dec. 31, 1996.

Market risks associated with these agreements result from short-term interest rate fluctuations. Credit risk related to nonperformance of the counterparties is not deemed significant, but would result in NSP terminating the swap transaction and recognizing a gain or loss, depending on the fair market value of the swap. The interest rate swaps serve to hedge the market risk associated with fixed rate debt in a declining interest rate environment. This hedge is produced by the tendency for changes in the fair market value of the swap to be offset by changes in the present value of the liability attributable to the fixed rate debt issued in conjunction with the interest rate swaps. If the interest rate swaps had been discontinued on Dec. 31, 1996, $2.0 million would have been payable by NSP, while the present value of the related fixed rate debt was $3.5 million below carrying value.

NRG has entered into seven forward foreign currency exchange contracts with counterparties to hedge exposure to currency fluctuations to the extent permissible by hedge accounting requirements. Pursuant to these contracts, transactions have been executed that are designed to protect the economic value in U.S. dollars of NRG's equity investments and retained earnings, denominated in Australian dollars and German deutsche marks (DM). As of Dec. 31, 1996, NRG had $132 million of foreign currency denominated assets that were hedged by forward foreign currency exchange contracts with a notional value of $123 million. In addition, NRG had approximately $82 million of foreign currency denominated retained earnings from foreign projects that were hedged by forward foreign currency exchange contracts with a notional value of $59 million. Because the effects of both currency translation adjustments to foreign investments and currency hedge instrument gains and losses are recorded on a net basis in Investments in Subsidiary Companies (not earnings), the impact of significant changes in currency exchange rates on these items would have an immaterial effect on NSP's financial condition and results of operations. The forward foreign currency exchange contracts terminate in 1998 through 2006 and require foreign currency interest payments by either party during each year of the contract. If the contracts had been terminated at Dec. 31, 1996, $13.3 million would have been payable by NRG for currency exchange rate changes to date. Management believes NRG's exposure to credit risk due to nonperformance by the counterparties to its forward exchange contracts is not significant, based on the investment grade rating of the counterparties.

Cenerprise has entered into natural gas futures contracts in the notional amount of $22 million at Dec. 31, 1996. The original contract terms range from one month to three years. The contracts are intended to mitigate risk from fluctuations in the price of natural gas that will be required to satisfy sales commitments for future deliveries to customers in excess of Cenerprise's natural gas reserves. Cenerprise's futures contracts hedge $22 million in anticipated natural gas sales in 1997-1998. The counterparties to the futures contracts are the New York Mercantile Exchange and major gas pipeline operators. Management believes that the risk of nonperformance by these counterparties is not significant. If the contracts had been terminated at Dec. 31, 1996, $0.5 million would have been payable to Cenerprise for natural gas price fluctuations to date.

Letters of Credit - NSP uses letters of credit to provide financial guarantees for certain operating obligations (including NSP workers' compensation benefits and ash disposal site costs, and Cenerprise natural gas purchases) and for nonregulated equity investment commitments. At Dec. 31, 1996, letters of credit of $70 million were outstanding. Generally, the letters of credit have terms of one year and are automatically renewed, unless prior written notice of cancellation is provided to NSP and the beneficiary by the issuing bank. The contract amounts of these letters of credit approximate their fair value and are subject to fees competitively determined in the marketplace.

10. RELATED PARTY TRANSACTIONS

Interchange Agreement - The electric production and transmission costs of the entire Northern States Power Company system are shared by the Company and its Wisconsin subsidiary. A FERC approved agreement (Interchange Agreement) between the two companies provides for the sharing of all costs of generation and transmission facilities of the system, including capital costs. Billings under the Interchange Agreement which are included in the Statement of Income are as follows (in thousands of dollars):

	1996	1995
Operating revenues:		
Electric	$187,081	$187,851
Gas	216	205
Operating expenses:		
Purchased and interchange power	45,323	46,072
Gas purchased for resale	39	43
Other operations	24,014	24,179

Gas Costs - The Company's subsidiary, Viking Gas Transmission Company (Viking), transports gas purchased by the Company from various suppliers. Under various contracts and agreements with Viking, which extend through 2008, the Company incurred transportation costs of $3.2 million in 1996 and $3.1 million in 1995 for gas purchased through Viking.

11. JOINT PLANT OWNERSHIP

The Company is a participant in a jointly owned 855-megawatt coal-fired electric generating unit, Sherburne County generating station unit No. 3 (Sherco 3), which began commercial operation Nov. 1, 1987. Undivided interests in Sherco 3 have been financed and are owned by the Company (59 percent) and Southern Minnesota Municipal Power Agency (41 percent). The Company is the operating agent under the joint ownership agreement. The Company's share of related expenses for Sherco 3 since commercial operations began are included in utility operating expenses. The Company's share of the gross cost recorded in Utility Plant at Dec. 31, 1996 and 1995, was $588,076,000 and $585,625,000, respectively. The corresponding accumulated provisions for depreciation were $168,641,000 and $150,022,000.

12. NUCLEAR OBLIGATIONS

Fuel Disposal - The Company is responsible for the temporary storage of used nuclear fuel from the Company's nuclear generating plants. Under a contract with the Company, the DOE is obligated to assume the responsibility for permanent storage or disposal of the Company's used nuclear fuel. The Company has been funding its portion of the DOE's permanent disposal program since 1981. Funding took place through an internal sinking fund until 1983, when the DOE began assessing fuel disposal fees under the Nuclear Waste Policy Act of 1982 based on a charge of 0.1 cent per kilowatt-hour sold to customers from nuclear generation. Fuel expense includes DOE fuel disposal assessments of $11.3 million and $12.3 million for 1996 and 1995, respectively. The cumulative amount of such assessments paid by the Company to the DOE through Dec. 31, 1996, was approximately $240 million. Currently, it is not determinable if the amount and method of the DOE's assessments to all utilities will be sufficient to fully fund the DOE's permanent storage or disposal facility.

The Nuclear Waste Policy Act stipulated that the DOE execute contracts with utilities that require DOE to begin accepting spent nuclear fuel no later than Jan. 31, 1998. Accordingly, the Company has been providing, with regulatory and legislative approval, its own temporary on-site storage facilities at its Monticello and Prairie Island nuclear plants, with a capacity sufficient for used fuel from the plants until at least that date. In 1996, the Company and 13 other major utilities were successful in a lawsuit against the DOE to clarify the DOE's obligation to accept spent nuclear fuel beginning in 1998. In July 1996, the U.S. Court of Appeals for the District of Columbia Circuit unanimously ruled that the Nuclear Waste Policy Act creates an unconditional obligation for the DOE to begin acceptance of spent nuclear fuel by Jan. 31, 1998. The DOE did not seek U.S. Supreme Court review. The ruling is a very positive development for the industry regarding concerns about the storage and disposal of used nuclear fuel. In December 1996, the DOE notified commercial spent fuel owners of an anticipated delay in accepting used nuclear fuel by the required date of Jan. 31, 1998, and conceded that a permanent storage or disposal facility will not be available until at least 2010. Because of the DOE's inadequate progress to provide a permanent repository, the MPUC is investigating whether continued payments to fund the DOE's permanent disposal program is prudent use of ratepayer money. The outcome of this investigation is unknown at this time. On Jan. 31, 1997, the Company, along with more than 30 other electric utilities and 45 state agencies, including the Minnesota Department of Public Service, filed another lawsuit against the DOE requesting authority to withhold payments to the DOE for the permanent disposal program. In the meantime, the Company is investigating all of its alternatives for used fuel storage until a DOE facility is available, including pursuing the establishment of a private facility for interim storage of used nuclear fuel as part of a consortium of electric utilities. If on-site temporary storage at the Company's nuclear plants reaches approved capacity, the Company could seek interim storage at this or another contracted private facility, if available.

In 1994, the Company received Minnesota legislative approval for additional on-site temporary storage facilities at its Prairie Island plant, provided the Company satisfies certain requirements. Seventeen dry cask containers, each of which can store approximately one-half year's used fuel, were approved to become available as follows: five immediately in 1994; four more in 1996 if an application for an alternative storage site is filed, an effort to locate such a site is made and 100 megawatts of wind generation is available or contracted for construction; and the final eight in 1999, unless the specified alternative site is not operational or under construction, or certain resource commitments are not met, and the Minnesota Legislature revokes its approval. (See additional discussion of legislative commitments in Note 13.) The Company has loaded used fuel into five of the dry cask containers as of Dec. 31, 1996, and in January 1997, loaded casks six and seven. With the dry cask storage facilities approved in 1994 for the Prairie Island nuclear generating plant, the Company believes it has adequate storage capacity to continue operation of its nuclear plants until at least 2003 and 2004 for Prairie Island Units 1 and 2, respectively. The Monticello nuclear plant has storage capacity to continue operations until 2010. Storage availability to permit operation beyond these dates is not assured at this time.

Nuclear fuel expenses in 1996 and 1995 include about $4 million and $5 million, respectively, for payments to the DOE for the decommissioning and decontamination of the DOE's uranium enrichment facilities. The DOE's initial assessment of $46 million to the Company was recorded in 1993. This assessment will be payable in annual installments from 1993-2008 and each installment is being amortized to expense on a monthly basis in the 12 months following each payment. The most recent installment paid in 1996 was $3.8 million; future installments are subject to inflation adjustments under DOE rules. The Company is obtaining rate recovery of these DOE assessments through the cost-of-energy adjustment clause as the assessments are amortized. Accordingly, the unamortized assessment of $41 million at Dec. 31, 1996, has been deferred as a regulatory asset as shown on page 232.

Plant Decommissioning - Decommissioning of all Company nuclear facilities is planned for the years 2010-2022, using the prompt dismantlement method. The Company is currently following industry practice by ratably accruing the costs for decommissioning over the approved cost recovery period and including the accruals in Utility Plant---Accumulated Depreciation, as discussed in Note 1. Consequently, the total decommissioning cost obligation and corresponding asset currently are not recorded in the Company's financial statements. The FASB has proposed new accounting standards which, if approved as expected in 1997, would require the full accrual of nuclear plant decommissioning and certain other site exit obligations beginning as soon as 1998. Using Dec. 31, 1996, estimates, the Company's adoption of the proposed accounting would result in the recording of the total discounted decommissioning obligation of $592 million as a liability, with the corresponding costs capitalized as plant and other assets and depreciated over the operating life of the plant. The obligation calculation methodology proposed by the FASB is slightly different from the ratemaking methodology that derives the decommissioning accruals currently being recovered in rates (as discussed below). The Company has not yet determined the potential impact of the FASB's proposed changes in the accounting for site exit obligations other than nuclear decommissioning (such as costs of removal). However, the ultimate decommissioning and site exit costs to be accrued are the same under both methods and, accordingly, the effects of regulation are expected to minimize or eliminate any impact on operating expenses and results of operations from this future accounting change.

Consistent with cost recovery in utility customer rates, the Company records 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. Since the costs are expected to be paid in 2010-2022, funding presumes that current costs will escalate in the future at a rate of 4.5 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 the assumed rate of return on funding, which is currently 6 percent (net of tax) for external funding and approximately 8 percent (net of tax) for internal funding.

The total obligation for decommissioning currently is expected to be funded approximately 82 percent by external funds and 18 percent by internal funds, as approved by the MPUC. Rate recovery of internal funding began in 1971 through depreciation rates for removal expense, and was changed to a sinking fund recovery in 1981. Contributions to the external fund started in 1990 and are expected to continue until plant decommissioning begins. Costs not funded by external trust assets (including accumulated earnings) will be funded through internally generated funds and issuance of Company debt or stock. The assets held in trusts as of Dec. 31, 1996, primarily consisted of investments in tax-exempt municipal bonds and U.S. government securities, which mature in three to 27 years and common stock of public companies. The Company plans to reinvest matured securities until decommissioning commences.

At Dec. 31, 1996, the Company has recorded and recovered in rates cumulative decommissioning accruals of $422 million. The following table summarizes the funded status of the Company's decommissioning obligation at Dec. 31, 1996:

(Thousands of dollars)	1996
Estimated decommissioning cost obligation from most recent approved study (1993 dollars)	$750,824
Effect of escalating costs to 1996 dollars (at 4.5% per year)	105,991
Estimated decommissioning cost obligation in current dollars	856,815
Effect of escalating costs to payment date (at 4.5% per year)	$987,970
Estimated future decommissioning costs (undiscounted)	$1,844,785
Effect of discounting obligation (using risk-free interest rate)	(1,253,038)
Discounted decommissioning cost obligation	591,747
External trust fund assets at fair value	260,756
Discounted decommissioning obligation in excess of assets currently held in external trust	$ 330,991

Decommissioning expenses recognized include the following components:

(Thousands of dollars)	1996	1995
Annual decommissioning cost accrual reported as depreciation expense:		
Externally funded	$33,178	$33,178
Internally funded (including interest costs)	1,268	1,174
Interest cost on externally funded decommissioning obligation	5,246	5,966
Earnings from external trust funds	(6,294)	(5,620)
Net decommissioning accruals recorded	$33,398	$34,698

Decommissioning and interest accruals are included with the accumulated provision for depreciation on the balance sheet. Interest costs and trust earnings associated with externally funded obligations are reported in Other Income and Deductions on the income statement.

The MPUC last approved a nuclear decommissioning study and related nuclear plant depreciation capital recovery request in 1994 based on a 1993 study. Although management expects to operate the Prairie Island units through the end of their licensed lives, the approved capital recovery would allow for the plant to be fully depreciated (including the accrual and recovery of decommissioning costs) in 2008, about six years earlier than the end of its licensed life. The approved recovery period for Prairie Island has been reduced because of the uncertainty regarding used fuel storage, as discussed previously. In October 1996, the Company submitted to the MPUC a revised nuclear decommissioning study. The filing recommends no change to current accruals and funding. Approval was received from the MPUC in February 1997. The Company believes future decommissioning cost accruals will continue to be recovered in customer rates.

13. COMMITMENTS AND CONTINGENT LIABILITIES

Legislative Resource Commitments - In 1994, the Minnesota Legislature established several energy resource and other commitments for the Company to fulfill to obtain the Prairie Island temporary nuclear fuel storage facility approval, as discussed in Note 12. The additional resource commitments, which can be met by building, purchasing or (in the case of biomass generation) converting generation resources are:

Power Type	Megawatts Required		Contract Deadline
Wind	100 (1)	(Additional)	12/31/96 (2)
Wind	100	(Additional)	12/31/98 (3)
Biomass	50	(Additional)	12/31/98 (4)
Wind	200	(Additional)	12/31/02
Biomass	75	(Additional)	12/31/98 (5)

(1) In addition to 25 megawatts of wind generation currently installed
(2) Contract pending MPUC approval
(3) Proposals under review by independent evaluator
(4) Developer selected for 75 megawatts; negotiating contract
(5) Solicited bids for remaining 50 megawatts of the 125-megawatt total biomass requirement

The Company is complying with the requirements of these resource commitments. Twenty-five megawatts of third party wind generation has been fully operational since May 1994. With respect to the additional 100 megawatts of wind energy to be under contract by the end of 1996, the Company has obtained a site designation from the Minnesota Environmental Quality Board (MEQB), and selected Zond Minnesota Development Corporation II (Zond) to supply the wind energy. The Company resolved a conflict over wind rights and other issues with an unsuccessful bidder, and signed an agreement with Zond allowing construction of the 100 megawatts of wind power. In October 1996, the Company issued a request for proposal for another 100-megawatt increment of wind power to fulfill the cumulative 225-megawatt requirement by Dec. 31, 1998. Bids were received on Feb. 7, 1997, and are being evaluated by an independent evaluator. A decision is expected by the summer of 1997.

In July 1996, Minnesota Agri-Power Project was selected to supply 75 megawatts of farm-grown, closed-loop biomass generation resources to be operational to the NSP system by Dec. 31, 2001. The 75 megawatts of biomass generation resources represents Phase I of the Company's legislative commitment to have 125 megawatts of such generation operational by Dec. 31, 2002.

Since 1994, the Company has spent nearly $3 million in a good faith effort to locate an alternate spent fuel storage site in Goodhue County, as required by the 1994 Minnesota Legislature. In 1995, the Company filed documents with the MEQB outlining two alternative Goodhue County sites to be considered for the development of an interim used nuclear fuel storage facility, as the Legislature required. In August 1996, the Company submitted a license application to the Nuclear Regulatory Commission (NRC) for an alternative site in Goodhue County to provide temporary storage for spent nuclear fuel. The application to the NRC was required before casks six through nine could be used at the existing facility for temporary spent nuclear fuel storage. In October 1996, the MEQB terminated the alternate spent fuel storage facility siting process in Goodhue County and certified that the Company has met the requirements necessary to use the casks at the Prairie Island nuclear generating facility. In October 1996, the Prairie Island Dakota Indian Tribe filed suit with the Minnesota Court of Appeals challenging the MEQB actions. The Company is defending the legality of the MEQB's actions. The Tribe also asked that the Court stay the MEQB actions while the lawsuit is pending, which would prevent the Company from using casks six through nine. In November 1996, the Court denied the Tribe's motion for a stay and referred the Tribe to the MEQB. In December 1996, the Tribe then asked that the MEQB stay its actions while the lawsuit is pending. In December 1996, the MEQB denied the Tribe's request for a stay of further loading of casks six through nine. In January 1997, the Tribe again requested the Court stay the MEQB actions during the pendency of the suit. The Company loaded casks six and seven in January 1997. In January 1997, the Court denied the Tribe's motion for a stay. A decision by the Court on the merits is expected in late spring 1997. In November 1996, the Company requested that the NRC put the license application on hold while the Court reviews the lawsuit by the Tribe. In December 1996, the NRC granted the Company's request to suspend review of the application.

Other commitments established by the Legislature include a low-income discount for electric customers, required conservation improvement expenditures and various study and reporting requirements to a legislative electric energy task force. In 1995, the MPUC approved the Company's low-income discount programs in accordance with the statute. The Company has implemented programs to begin meeting the other legislative commitments. The Company's capital commitments, disclosed below, include the known effects of the 1994 Prairie Island legislation. The impact of the legislation on power purchase commitments and other operating expenses is not yet determinable.

Capital Commitments - The Company estimates utility capital expenditures, including acquisitions of nuclear fuel, will be $340 million in 1997 and $1.6 billion for 1997-2001. There also are contractual commitments for the disposal of used nuclear fuel. (See Note 12.)

The Company's Wisconsin subsidiary presently estimates its utility capital expenditures will be $58 million in 1997 and $359 million for 1997-2001. The Company's Viking subsidiary presently estimates its utility capital expenditures will be $28 million in 1997 and $32 million for 1997-2001. Potential capital requirements for all nonregulated projects and property of the Company and its subsidiaries is estimated to be as much as $310 million in 1997 and $940 million for the five-year period 1997-2001.

As of Dec. 31, 1996, NRG is contractually committed to additional equity investments of approximately $37 million in 1997 and approximately $200 million for 1997-2001 for various international power generation projects. In addition, in 1996 NRG has provided a $10 million loan commitment to a wholly owned subsidiary of NRG Generating (U.S.) Inc. (NRGG), an unconsolidated affiliate of NRG, in order for the NRGG subsidiary to fund its capital contribution to a cogeneration project currently under construction. No funds have been disbursed to date on the commitment. However, NRG expects to fund this loan sometime in 1997. Also in 1996, NRG executed an agreement whereby NRG is obligated to provide to NRGG, power generation investment opportunities in the United States over a three-year period. These projects must have in aggregate, over the three-year term, an equity value of at least $60 million or a minimum of 150 net megawatts. In addition, NRG has committed to finance NRGG's investment in the projects to the extent funds are not available to NRGG on comparable terms from other sources.

Leases - Rentals under operating leases were approximately $24.4 million and $23.8 million for 1996 and 1995, respectively.

Fuel Contracts - NSP has contracts providing for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts, which expire in various years between 1997 and 2013, require minimum contractual purchases and deliveries of fuel, and additional payments for the rights to purchase coal in the future. In total, the Company is committed to the minimum purchase of approximately $415 million of coal, $20 million of nuclear fuel and $229 million of natural gas and related transportation, or to make payments in lieu thereof, under these contracts. In addition, the Company is required to pay additional amounts depending on actual quantities shipped under these agreements. The Wisconsin Company is committed to the minimum purchase of approximately $156 million of natural gas and related transportation, or to make payments in lieu thereof, under these contracts. As a result of FERC Order 636, NSP has been very active in developing a mix of gas supply, transportation and storage contracts designed to meet its needs for retail gas sales. The contracts are with several suppliers and for various periods of time. Because NSP has other sources of fuel available and suppliers are expected to continue to provide reliable fuel supplies, risk of loss from nonperformance under these contracts is not considered significant. In addition, NSP's risk of loss (in the form of increased costs) from market price changes in fuel is mitigated through the cost-of-energy adjustment provision of the ratemaking process, which provides for recovery of nearly all fuel costs.

Power Agreements - The Company has executed several agreements with the Manitoba Hydro-Electric Board (MH) for hydroelectricity. A summary of the agreements is as follows:

	Years	Megawatts
Participation Power Purchase	1997-2005	500
Seasonal Diversity Exchanges:		
Summer exchanges from MH	1997-2014	150
	1997-2016	200
Winter exchanges to MH	1997-2014	150
	1997-2015	200
	2015-2017	400
	2018	200

The cost of the 500-megawatt participation power purchase commitment is based on 80 percent of the costs of owning and operating the Company's Sherco 3 generating plant (adjusted to 1993 dollars). The future annual capacity costs for all MH agreements is estimated to be approximately $58 million. These commitments to MH, which represent about 18 percent of MH's system capability in 1997 and account for approximately 10 percent of NSP's 1997 electric system capability. The risk of loss from nonperformance by MH is not considered significant, and the risk of loss from market price changes is mitigated through cost-of-energy rate adjustments.

The Company has an agreement with Minnkota Power Cooperative for the purchase of summer season capacity and energy. From 1997 through 2001, the Company will buy 150 megawatts of summer season capacity for $12 million annually. From 2002 through 2015, the Company will purchase 100 megawatts of capacity for $10 million annually. Under the agreement, energy will be priced against the cost of fuel consumed per megawatt-hour at the Coyote Generating Station in North Dakota. The Company also has a seasonal (summer) purchase power agreement with Minnesota Power for the purchase of 173 megawatts, including reserves, from 1997-2000. The annual cost of this capacity will be approximately $2 million.

The Company has agreements with several nonregulated power producers to purchase electric capacity and associated energy. The 1997 cost of these commitments for nonregulated installed capacity is approximately $36 million for 379 megawatts of summer capacity. This annual cost will increase to approximately $37 million-$44 million for 1998-2018 and then decrease to approximately $25 million-$29 million for 2019-2027 due to the expiration of existing agreements and an additional agreement for the purchase of 245 to 262 megawatts effective May 1997.

Nuclear Insurance - The Company's public liability for claims resulting from any nuclear incident is limited to $8.9 billion under the 1988 Price-Anderson amendment to the Atomic Energy Act of 1954. The Company has secured $200 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $8.7 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. The Company is subject to assessments of up to $79 million 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 $10 million per reactor during any one year.

The Company purchases insurance for property damage and site decontamination cleanup costs with coverage limits of $2.0 billion for each of the Company's two nuclear plant sites. The coverage consists of $500 million from Nuclear Mutual Limited (NML) and $1.5 billion from Nuclear Electric Insurance Limited (NEIL).

NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums billed to the Company from NML and NEIL are expensed over the policy term. All companies insured with NML and NEIL are subject to retrospective premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NML and NEIL to the extent that the Company would have no exposure for retrospective premium assessments in case of a single incident under the business interruption and the property damage insurance coverages. However, in each calendar year, the Company could be subject to maximum assessments of approximately $5 million (five times the amount of its annual premium) and $26 million (generally five times the amount of its annual premium) if losses exceed accumulated reserve funds under the business interruption and property damage coverages, respectively.

Environmental Contingencies - Other non-current liabilities and deferred credits include an accrual of $40 million, and other current liabilities include an accrual of $5 million at Dec. 31, 1996, for estimated costs associated with environmental remediation. Approximately $34 million of the long-term liability and $4 million of the current liability relate to a DOE assessment for decommissioning of a federal uranium enrichment facility, as discussed in Note 12. Other estimates have been recorded for expected environmental costs associated with manufactured gas plant sites formerly used by the Company and other waste disposal sites, as discussed below.

These environmental liabilities do not include accruals recorded (and collected from customers in rates) for future nuclear fuel disposal costs or decommissioning costs related to the Company's nuclear generating plants. (See Note 12 for further discussion.)

The Environmental Protection Agency (EPA) or state environmental agencies have designated the Company as a "potentially responsible party" (PRP) for 13 waste disposal sites to which the Company allegedly sent hazardous materials. Nine of these 13 sites have been remediated and, consistent with settlements reached with the EPA and other PRPs, the Company has paid $1.7 million for its share of the remediation costs. While these remediated sites will continue to be monitored, the Company expects that future remediation costs, if any, will be immaterial. Under applicable law, the Company, along with each PRP, could be held jointly and severally liable for the total remediation costs of PRP sites. Of the four unremediated sites, the total remediation costs are currently estimated to be approximately $18 million. If additional remediation is necessary or unexpected costs are incurred, the amount could be higher. The Company is not aware of the other parties' inability to pay, nor does it know if responsibility for any of the sites is in dispute. For these four sites, neither the amount of remediation costs nor the final method of their allocation among all designated PRPs has been determined. However, the Company has recorded an estimate of approximately $1.4 million for its share of future costs for these four sites, including $0.6 million, which is expected to be paid in 1997. While it is not feasible to determine the ultimate impact of PRP site remediation at this time the amounts accrued represent the best current estimate of the Company's future liability. It is the Company's practice to vigorously pursue and, if necessary, litigate with insurers to recover incurred remediation costs whenever possible. Through litigation, the Company has recovered from other PRPs a portion of the remediation costs paid to date. Management believes remediation costs incurred, but not recovered from insurance carriers or other parties, should be allowed recovery in future ratemaking. Until the Company is identified as a PRP, it is not possible to predict the timing or amount of any costs associated with sites, other than those discussed above.

The Wisconsin Company potentially may be involved in the cleanup and remediation at four sites. Two sites are solid and hazardous waste landfill sites in Eau Claire and Amery, Wis. The Wisconsin Company contends that it did not dispose of hazardous wastes in these landfills during the time period in question. Because neither the amount of cleanup costs nor the final method of their allocation among all designated PRPs has been determined, it is not feasible to predict the outcome of these matters at this time. The third site is a landfill in Hudson, Wis., which is one of the PRP waste disposal sites discussed previously as part of the Company's sites. The fourth site, in Ashland, Wis., contains creosote/coal tar contamination. In 1995, the Wisconsin Department of Natural Resources (WDNR) notified the Wisconsin Company that it is a PRP at this site. At this time, the WDNR has determined that the Wisconsin Company is the only PRP at this site. WDNR's consultant is preparing a remedial option study for the entire Ashland site, which includes the Wisconsin Company's portion and two other adjacent portions. Until this study is completed and more information is known concerning the extent of the final remediation required by the WDNR, the remediation method selected, the related costs, the various parties involved, and the extent of the Wisconsin Company's responsibility, if any, for sharing the costs, the ultimate cost to the Wisconsin Company and timing of any payments related to the Ashland site are not determinable. At Dec. 31, 1996, the Company had recorded an estimated liability of $900,000 for future remediation costs associated with the Wisconsin Company-owned portion of the Ashland site. Through Dec. 31, 1996, the Wisconsin Company has incurred approximately $525,000 in actual expenditures, excluding future remediation costs for this site. Based on a recent Public Service Commission of Wisconsin decision to allow recovery of incremental costs incurred for this site in 1997 rates, the Wisconsin Company has recorded a regulatory asset for the accrued and actual expenditures related to the Ashland site. The ultimate cleanup and remediation costs at the Eau Claire, Amery and Ashland sites and the extent of the Wisconsin Company's responsibility, if any, for sharing such costs are not known at this time, but may be significant.

The Company also is continuing to investigate various properties, which it presently or previously owned. The properties were formerly sites of gas manufacturing, gas storage plants or gas pipelines. The purpose of this investigation is to determine if waste materials are present, if they are an environmental or health risk, if the Company has any responsibility for remedial action and if recovery under the Company's insurance policies can contribute to any remediation costs. The Company has already remediated one site, which continues to be monitored. The Company has paid $2.5 million to remediate this site and expects to incur in the future only immaterial monitoring costs related to this remediated site. Another 14 gas sites remain under investigation, and the Company is actively taking remedial action at four of the sites. In addition, the Company has been notified that two other sites eventually will require remediation, and a study was initiated in 1996 to determine the cost and method of cleanup, which is expected to begin in 1997. As of Dec. 31, 1996, the Company has paid $5.4 million on these six active sites and has recorded an estimated liability of approximately $4.8 million for future costs, with payment expected over the next 10 years. This estimate is based on prior experience and includes investigation, remediation and litigation costs. As for the eight inactive sites, no liability has been recorded for remediation or investigation because the present land use at each of these sites does not warrant a response action. While it is not feasible to determine at this time the ultimate costs of gas site remediation, the amounts accrued represent the best current estimate of the Company's future liability for any required cleanup or remedial actions at these former gas operating sites. Management also believes that incurred costs, which are not recovered from insurance carriers or other parties, should be allowed recovery in future ratemaking. During 1994, the Company's gas utility received approval for deferred accounting for certain gas remediation costs incurred at four active sites, with final rate treatment of such costs to be determined in future general gas rate cases.

The Clean Air Act, including the Amendments of 1990 (the Clean Air Act), calls for reductions in emissions of sulfur dioxide and nitrogen oxides from electric generating plants. These reductions, which will be phased in, began in 1995. The majority of the rules implementing this complex legislation has been finalized. The Company has invested significantly over the years to reduce sulfur dioxide emissions at its plants. No additional capital expenditures are anticipated to comply with the sulfur dioxide emission limits of the Clean Air Act. The Company is still evaluating how best to implement the nitrogen oxides standards. The Company's capital expenditures include some costs for ensuring compliance with the Clean Air Act's other emission requirements; other expenditures may be necessary upon EPA's finalization of remaining rules. Because the Company is still in the process of implementing some provisions of the Clean Air Act, its total financial impact is unknown at this time. Capital expenditures for opacity compliance are considered in the capital expenditure commitments disclosed previously. The depreciation of these capital costs will be subject to regulatory recovery in future rate proceedings.

Several of the Company's operating facilities have asbestos-containing material, which represents a potential health hazard to people who come in contact with it. Governmental regulations specify the timing and nature of disposal of asbestos-containing materials. Under such requirements, asbestos not readily accessible to the environment need not be removed until the facilities containing the material are demolished. Although the ultimate cost and timing of asbestos removal is not yet known, it is estimated that removal under current regulations would cost $47 million in 1996 dollars. Depending on the timing of asbestos removal, such costs would be recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects, or removal costs for demolition projects.

Environmental liabilities are subject to considerable uncertainties that affect NSP's ability to estimate its share of the ultimate costs of remediation and pollution control efforts. Such uncertainties involve the nature and extent of site contamination, the extent of required cleanup efforts, varying costs of alternative cleanup methods and pollution control technologies, changes in environmental remediation and pollution control requirements, the potential effect of technological improvements, the number and financial strength of other potentially responsible parties at multi-party sites and the identification of new environmental cleanup sites. The Company has recorded and/or disclosed its best estimate of expected future environmental costs and obligations, as discussed previously.

Legal Claims - In the normal course of business, the Company is a party to routine claims and litigation arising from prior and current operations. The Company is actively defending these matters and has recorded an estimate of the probable cost of settlement or other disposition.

In 1993, a natural gas explosion occurred on the Company's distribution system in St. Paul, Minn. In 1995, the National Transportation Safety Board found little, if any, fault with the Company's actions or conduct. Total damages related to the explosion are estimated to exceed $1 million. The Company has a self-insured retention deductible of $1 million, with general liability coverage of $150 million, which includes coverage for all injuries and damages. Eighteen lawsuits have been filed, including one suit with multiple plaintiffs. In February 1997, the Company settled six of the lawsuits, including all of the death and serious burn cases. Most, if not all, of the settlement will be paid by the Company's insurer. Additional mediation is scheduled for early 1997. A trial to decide any additional civil liability and the parties responsible for the explosion has been scheduled for May 1997, with the damages portion of the trial scheduled for six months thereafter. The ultimate costs to the Company are unknown at this time.

In late 1996, the Company was named in a class action lawsuit commenced by two of the Company's commercial customers who claim that the expected energy savings from the Company's lighting efficiency program were misrepresented. The Company denies all liability with respect to the customers' claims. However, the ultimate costs to the Company, if any, are unknown at this time.

14. MERGER AGREEMENT WITH WISCONSIN ENERGY CORPORATION

As previously reported in the Company's Current Report on Form 8-K, dated April 28, 1995, and filed with the Securities and Exchange Commission (SEC) on May 3, 1995, and SEC Quarterly Reports on Form 10-Q, the Company and Wisconsin Energy Corporation (WEC) have entered into an Agreement and Plan of Merger (Merger Agreement), which provides for a business combination involving the Company and WEC in a "merger-of-equals" transaction (the Transaction) intended to be accounted for as a "pooling of interests".

The Transaction - Under the Merger Agreement, Primergy Corporation (Primergy), which will be registered under the Public Utility Holding Company Act of 1935, as amended, will become the parent company of both the Company (which, for regulatory reasons, will reincorporate in Wisconsin) and WEC's current principal utility subsidiary, Wisconsin Electric Power Company, which will be renamed "Wisconsin Energy Company." It is anticipated that, following the Transaction, except for certain gas distribution properties transferred to the Company, the Company's Wisconsin subsidiary will be merged into Wisconsin Energy Company and that some of the Company's other subsidiaries will become direct Primergy subsidiaries.

As noted above, pursuant to the Transaction, the Company will reincorporate in Wisconsin. This reincorporation will be accomplished by the merger of the Company into a new company, Northern Power Wisconsin Corporation (New NSP), with New NSP being the surviving corporation and succeeding to the business of the Company as an operating public utility. Following such merger, a new WEC subsidiary, WEC Sub Corporation (WEC Sub), will be merged with and into New NSP, with New NSP being the surviving corporation and becoming a subsidiary of Primergy. Both New NSP and WEC Sub were created to effect the Transaction and will not have any significant operations, assets or liabilities prior to such mergers. After the Transaction is completed, current common stockholders of the Company will own shares of Primergy common stock, and current bondholders and preferred stockholders of the Company will become investors in New NSP.

On Sept. 13, 1995, more than 95 percent of the respective shareholders of the Company and WEC voting approved the merger plan at their respective shareholders meetings. Under the proposed business combination, shareholders of the Company would receive 1.626 shares of Primergy common stock for each share of the Company's common stock owned at the time of the merger.

The business combination is intended to be tax-free for income tax purposes. During 1995, the Company and WEC received a ruling from the Internal Revenue Service indicating that the proposed successive merger transactions would not prevent treatment of the business combination as a tax-free reorganization under applicable tax law if each transaction independently qualified.

Regulatory Approvals - The agreement to merge is subject to approval by applicable regulatory authorities. During 1995, the Company and WEC submitted filings to the FERC, applicable state regulatory commissions and other governmental authorities seeking approval of the proposed merger to form Primergy.

The goal of the Company and WEC was to complete the merger by year-end 1996. However, all necessary regulatory approvals were not obtained by the end of 1996 and, as a result, the merger was not completed in 1996. The Company and WEC continue to pursue regulatory approvals, without unacceptable conditions, to allow completion of the merger as soon as possible in 1997.

Each of the state filings included a request for deferred accounting treatment and rate recovery of amortized costs incurred in connection with the proposed merger. At Dec. 31, 1996, \$24.5 million of costs associated with the proposed merger had been deferred as a component of Miscellaneous Deferred Debits. If the merger is not completed, these costs would be charged to expense.

Although the Company and WEC are working to avoid divestitures, the PUHCA may require the merged entity to divest certain of its gas utility and/or nonregulated operations. Also, regulatory authorities may require the use of an independent transmission system operator (ISO) or divestiture of certain transmission and/or generation assets. The Company currently cannot determine if such divestitures would be required by regulators. In addition, Wisconsin state law limits the total assets of nonutility affiliates of Primergy, which, as presently interpreted, would affect the growth of nonregulated operations.

In addition to the regulatory and other governmental approvals required to complete the proposed merger, certain NSP financial and other agreements may be construed to require that, in the case of a change in ownership (such as the proposed merger), the other party to the agreement must consent to the change or waive the requirement. Agreements with such provisions at Dec. 31, 1996, include \$106 million of long-term debt and a \$10 million credit line agreement, under which short-term borrowings totalled \$3.7 million at Dec. 31, 1996. In January 1997, the PSCW adopted new rules establishing standards of conduct for retail natural gas utilities in Wisconsin, including the Wisconsin Company. The rules will necessitate PSCW approval of Primergy's contemplated regulated gas operating arrangements, on which a portion of the projected merger savings are based. NSP will timely seek all necessary approvals.

Under the Merger Agreement, completion of the merger is subject to numerous conditions, that, unless waived by the affected party, must be met, including but not limited to: the prior receipt of all necessary regulatory approvals without the imposition of materially adverse terms; the accuracy of each party's representations and warranties in the Merger Agreement, other than representations and warranties whose inaccuracy does not result in a material adverse effect on the business, assets, financial condition, results of operations or prospects of such party and its subsidiaries taken as a whole; and no such material adverse effect having occurred, or being reasonably likely to occur, with respect to either party. In addition, both WEC and NSP have the right to terminate the Merger Agreement under certain circumstances, including without limiting the foregoing, the inability to fulfill all conditions to the closing of the merger at April 30, 1997 (other than receipt of all regulatory approvals without any materially adverse terms), or the failure to receive all regulatory approvals without any materially adverse terms by Oct. 31, 1997. NSP continues to work with WEC to complete the merger. However, since numerous conditions are beyond its control, NSP cannot state whether all necessary conditions for completion of the merger will occur.

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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

Line No.	Item (a)	Total (b)	Electric (c)
1	UTILITY PLANT		
2	In Service		
3	Plant in Service (Classified)	$6,501,186,586	$5,748,446,185
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	TOTAL (Enter Total of lines 3 thru 7)	$6,501,186,586	$5,748,446,185
9	Leased to Others	2,642,721	2,642,721
10	Held for Future Use	4,646,298	685,245
11	Construction Work in Progress	156,930,471	120,756,827
12	Acquisition Adjustments	222,385	222,385
13	TOTAL Utility Plant (Enter total of lines 8 thru 12)	$6,665,628,461	$5,872,753,363
14	Accum. Prov. for Depr., Amort., & Depl.	3,139,136,901	2,850,299,244
15	Net Utility Plant (Enter Total of line 13 less 14)	$3,526,491,560	$3,022,454,119
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION		
17	In Service:		
18	Depreciation	3,111,964,713	2,846,878,940
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights		
20	Amort. of Underground Storage Land and Land Rights		
21	Amort. of Other Utility Plant	26,375,561	2,623,677
22	TOTAL In Service (Enter Total of lines 18 thru 21)	$3,138,340,274	$2,849,502,617
23	Leased to Others		
24	Depreciation	752,131	752,131
25	Amortization and Depletion	0	
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)	$752,131	$752,131
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort. of Plant Aquisition Adj.	44,496	44,496
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22,26,30,31 and 32)	$3,139,136,901	$2,850,299,244

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.
[redacted]					1
					2
$523,677,488				$229,062,913	3
					4
					5
					6
					7
$523,677,488				$229,062,913	8
					9
				3,961,053	10
5,017,951				31,155,693	11
					12
$528,695,439				$264,179,659	13
198,058,683				90,778,974	14
$330,636,756				$173,400,685	15
[redacted]					16
					17
198,058,683				67,027,090	18
	[redacted]				19
					20
				23,751,884	21
$198,058,683				$90,778,974	22
[redacted]					23
					24
					25
					26
[redacted]					27
					28
					29
					30
	[redacted]				31
					32
$198,058,683				$90,778,974	33

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

NUCLEAR FUEL MATERIALS (Accounts 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, Conversion, Enrichment & Fabrication (120.1)		
2	Fabrication	4,607,587	12,634,460
3	Nuclear Materials	28,655,332	34,894,432
4	Allowance for Funds Used during Construction	596,858	714,177
5	(Other Overhead Construction Costs)	375,176	322,272
6	SUBTOTAL (Enter Total of lines 2 thru 5)	$34,234,953	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		75,884,379
9	In Reactor (120.3)	218,184,044	50,724,018
10	SUBTOTAL (Enter Total of lines 8 thru 9)	$218,184,044	
11	Spent Nuclear Fuel (120.4)	591,499,782	51,309,863
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum. Prov. for Amortization of Nuclear Fuel Assemblies (120.5)	752,821,108	
14	TOTAL Nuclear Fuel Stock (Enter Total lines 6, 10, 11, and 12 less line 13)	$91,097,671	
15	Estimated net Salvage Value of Nuclear Materials in line 9	*	
16	Estimated net Salvage Value of Nuclear Materials in line 11	*	
17	Estimated net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other		
22	TOTAL Nuclear Materials held for Sale Enter Total of lines 19, 20, and 21		

< Page 202 Line 15 Column b >

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

< Page 202 Line 16 Column b >

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

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

NUCLEAR FUEL MATERIALS (Accounts 120.1 through 120.6 and 157)(Continued)

Changes During the Year			
Amortization (d)	Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)	Line No.
			1
	* 15,454,949	1,787,098	2
	* 58,617,940	4,931,824	3
	* 1,162,767	148,268	4
	* 648,723	48,725	5
		$6,915,915	6
			7
	* 50,344,379	25,540,000	8
	* 51,309,863	217,598,199	9
		$243,138,199	10
	* 379,639	642,430,006	11
		0	12
(45,773,602)	* 6,448,412	792,146,298	13
		$100,337,822	14
			15
			16
			17
		0	18
		0	19
		0	20
		0	21
		0	22

< Page 203 Line 2 Column e >
Classified to Account 120.2

< Page 203 Line 3 Column e >
Classified to Account 120.2

< Page 203 Line 4 Column e >
Classified to Account 120.2

< Page 203 Line 5 Column e >
Classified to Account 120.2

< Page 203 Line 8 Column e >
Transferred to Account 120.3

< Page 203 Line 9 Column e >
Transferred to Account 120.4

< Page 203 Line 11 Column e >
Reinserted into the reactor

< Page 203 Line 13 Column e >
Transferred to Account 321

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.

2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.

3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.

4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.

5. 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) reversals of tentative distributions of prior year of unclassified retirements. Show in a footnote the account distributions of these tentative classifications in columns (c) and (d), including the

Line No.	Account (a)	Balance at Beginning of Year (b)	Addition (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant	2,473,962	600,417
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	$2,473,962	$600,417
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	8,823,759	407,830
9	(311) Structures and Improvements	289,274,140	7,167,546
10	(312) Boiler Plant Equipment	917,713,756	3,572,540
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	225,954,652	2,520,531
13	(315) Accessory Electric Equipment	136,758,086	8,464,558
14	(316) Misc. Power Plant Equipment	59,625,602	1,059,500
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	$1,638,149,995	$23,192,505
16	B. Nuclear Production Plant		
17	(320) Land and Land Rights	1,145,060	
18	(321) Structures and Improvements	298,823,731	9,517,011
19	(322) Reactor Plant Equipment	567,515,735	2,772,209
20	(323) Turbo generator Units	143,772,209	29,899,680
21	(324) Accessory Electric Equipment	199,748,566	497,917
22	(325) Misc. Power Plant Equipment	134,140,681	1,962,935
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)	$1,345,145,982	$44,649,752
24	C. Hydraulic Production Plant		
25	(330) Land and Land Rights	1,698,851	
26	(331) Structures and Improvements	442,146	
27	(332) Reservoirs, Dams, and Waterways	2,724,823	
28	(333) Water Wheels, Turbines, and Generators	1,140,299	
29	(334) Accessory Electric Equipment	302,701	
30	(335) Misc. Power Plant Equipment	42,069	
31	(336) Roads, Railroads, and Bridges		
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)	$6,350,889	
33	D. Other Production Plant		
34	(340) Land and Land Rights	2,882,354	
35	(341) Structures and Improvements	8,293,240	159,221
36	(342) Fuel Holders, Products, and Accessories	4,314,817	
37	(343) Prime Movers		
38	(344) Generators	120,794,281	1,540,691
39	(345) Accessory Electric Equipment	7,220,457	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

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.

6. 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. In showing the clearance of 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.

7. 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 requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, 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 of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
[redacted]					1
				(301)	2
				(302)	3
			3,074,379	(303)	4
			$3,074,379		5
[redacted]					6
					7
			9,231,589	(310)	8
262,134			296,179,552	(311)	9
639,506	453,000		921,099,790	(312)	10
			0	(313)	11
168,873			228,306,310	(314)	12
32,980			145,189,664	(315)	13
14,883	92,164		60,762,383	(316)	14
$1,118,376	$545,164		$1,660,769,288		15
[redacted]					16
			1,145,060	(320)	17
1,520,031		(437,060)	306,820,711	(321)	18
6,386,285		429,024	564,330,683	(322)	19
11,809,610	679,311		162,541,590	(323)	20
3,138,981			197,107,502	(324)	21
2,409,067		(63,736)	133,630,813	(325)	22
$25,263,974	$679,311	($71,772)	$1,365,139,299		23
[redacted]					24
			1,698,851	(330)	25
			442,146	(331)	26
			2,724,823	(332)	27
			1,140,299	(333)	28
	(31,871)		270,830	(334)	29
			42,069	(335)	30
				(336)	31
	($31,871)		$6,319,018		32
[redacted]					33
			2,882,354	(340)	34
			8,452,461	(341)	35
			4,314,817	(342)	36
				(343)	37
589,544		8,930	121,754,358	(344)	38
			7,220,457	(345)	39

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
40	(346) Misc. Power Plant Equipment	$487,963	$1,786,676
41	TOTAL Other Prod. Plant (Enter Total of lines 34 thru 40)	$143,993,112	$3,486,588
42	TOTAL Prod. Plant (Enter Total of lines 15, 23, 32, and 41)	$3,133,639,978	$71,328,845
43	3. TRANSMISSION PLANT		
44	(350) Land and Land Rights	36,122,138	575,945
45	(352) Structures and Improvements	10,816,002	223,571
46	(353) Station Equipment	289,135,872	22,983,519
47	(354) Towers and Fixtures	92,641,884	447,731
48	(355) Poles and Fixtures	100,210,805	5,831,159
49	(356) Overhead Conductors and Devices	120,742,250	4,541,646
50	(357) Underground Conduit	4,784,351	750,000
51	(358) Underground Conductors and Devices	4,360,931	2,954,868
52	(359) Roads and Trails		
53	TOTAL Transmission Plant (Enter Total of lines 44 thru 52)	$658,814,233	$38,308,439
54	4. DISTRIBUTION PLANT		
55	(360) Land and Land Rights	8,452,646	2,138,452
56	(361) Structures and Improvements	20,489,102	1,956,961
57	(362) Station Equipment	236,724,374	18,305,875
58	(363) Storage Battery Equipment		
59	(364) Poles, Towers, and Fixtures	152,702,177	7,915,578
60	(365) Overhead Conductors and Devices	180,228,810	11,849,744
61	(366) Underground Conduit	81,328,324	4,629,142
62	(367) Underground Conductors and Devices	404,330,811	32,630,971
63	(368) Line Transfomers	237,396,985	14,871,858
64	(369) Services	141,108,630	9,432,152
65	(370) Meters	90,666,572	5,328,517
66	(371) Installations on Customer Premises	21,958,559	378,372
67	(372) Leased Property on Customer Premises		
68	(373) Street Lighting and Signal Systems	23,390,891	1,116,651
69	TOTAL Distribution Plant (Enter Total of lines 55 thru 68)	$1,598,777,881	$110,554,273
70	5. GENERAL PLANT		
71	(389) Land and Land Rights	4,649,486	473
72	(390) Structures and Improvements	42,417,813	1,041,387
73	(391) Office Furniture and Equipment	17,399,518	3,530,345
74	(392) Transportation Equipment	31,739,906	
75	(393) Stores Equipment	1,961,690	
76	(394) Tools, Shop and Garage Equipment	21,220,928	1,629,162
77	(395) Laboratory Equipment	6,631,597	264,373
78	(396) Power Operated Equipment	4,885,399	
79	(397) Communication Equipment	35,170,200	3,997,364
80	(398) Miscellaneous Equipment	463,449	10,058
81	SUBTOTAL (Enter Total of lines 71 thru 80)	$166,539,986	$10,473,162
82	(399) Other Tangible Property		
83	TOTAL General Plant (Enter Total of lines 81 and 82)	$166,539,986	$10,473,162
84	TOTAL (Accounts 101 and 106) (lines 5,15,23,32,41,53,69,83)	$5,560,246,040	$231,265,136
85	(102) Electric Plant Purchased (See Instr. 8)		
86	(Less) (102) Electric Plant Sold (See Instr. 8)		
87	(103) Experimental Plant Unclassified		
88	TOTAL Electric Plant in Service (Enter Total of lines 84 thru 87)	$5,560,246,040	$231,265,136

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of year (g)		Line No.
			$2,274,639	(346)	40
$589,544		$8,930	$146,899,086		41
$26,971,894	$1,192,604	($62,842)	$3,179,126,691		42
					43
1,543			36,696,540	(350)	44
226		102,902	11,142,249	(352)	45
1,224,124	(89,954)	5,317	310,810,630	(353)	46
58,444			93,031,171	(35[illegible])	47
489,128		(263,654)	105,552,836	(355)	48
1,007,759		263,654	124,539,791	(356)	49
			5,534,351	(357)	50
			7,315,799	(358)	51
				(359)	52
$2,781,224	($89,954)	$108,219	$694,359,713		53
					54
1,809			10,589,289	(360)	55
177,861			22,268,202	(361)	56
1,700,870		(157,149)	253,329,379	(362)	57
			0	(363)	58
1,330,014		2,539	159,287,741	(364)	59
2,458,589		105,065	189,619,965	(365)	60
75,289		6,880	85,889,057	(366)	61
2,735,038		82,793	434,226,744	(367)	62
3,187,061	316,567	(1,615)	249,398,349	(368)	63
539,984		(12,097)	150,000,798	(369)	64
3,108,112	51,067	50	92,938,094	(370)	65
1,320			22,335,611	(371)	66
			0	(372)	67
110,953			24,396,589	(373)	68
$15,426,900	$367,634	$26,466	$1,694,299,354		69
					70
			4,649,959	(389)	71
100,921	(945)		43,357,334	(390)	72
		71,772	21,001,635	(391)	73
			31,739,906	(392)	74
			1,961,690	(393)	75
			22,850,090	(394)	76
			6,895,970	(395)	77
			4,885,399	(396)	78
320,421		923,415	38,847,143	(397)	79
			473,507	(398)	80
$421,342	($945)	$995,187	$177,586,048		81
			0	(399)	82
$421,342	($945)	$995,187	$177,586,048		83
$45,601,360	$1,469,339	$1,067,030	$5,748,446,185		84
				(102)	85
					86
				(103)	87
$45,601,360	$1,469,339	$1,067,030	$5,748,446,185		88

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

1. Report below the information called for concerning electric plant leased to others.

2. In column (c) give the date of Commission authorization of the lease of electric plant to others.

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	NA	NA	$2,642,721
2		115 KV Transmission Line #5509			
3		and a portion of a Transmission			
4		Substation			
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47	TOTAL				$2,642,721

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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:	[redacted]		
2	Distribution Substation Sites			$319,144
3				
4				
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19				
20				
21	Other Property:	[redacted]		
22	Distribution Substation Structure & Improvements			184,874
23	Distribution Conduit and Conductors			159,625
24	Transmission Poles and Conductors			21,602
25				
26				
27				
28				
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47	TOTAL	[redacted]		$685,245

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 Demonstration (see Account 107 of the Uniform System of Accounts).

3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)
1	PRODUCTION PLANT	
2	A S King - Property purchase for Future Landfill	524,204
3	Angus Anson - Pipeline Pathfinder Project	618,210
4	Black Dog - Install Diesel Generators for System Restoration Support	154,403
5	High Bridge - Coal Handling Electrical Safety Improvements	1,342,807
6	High Bridge - Install Diesel Generators for System Restoration Support	105,887
7	High Bridge - Riverfront Improvements	201,448
8	Inver Hills - Install Diesel Generators for System Restoration Support	647,217
9	King - Boiler Room Roof Replacement	146,977
10	Lake Benton - Wind Generation - Land Rights	5,451,583
11	Lake Benton - Wind Generation - Land Rights	525,682
12	Prairie Island - 480 Volt Common Unit Loads	351,152
13	Prairie Island - Alternate Site Spent Fuel Storage Installation	2,150,249
14	Prairie Island - Alternate Site Spent Fuel Storage Installation	761,719
15	Prairie Island - Ancillary Structures Roof Replacement	161,963
16	Prairie Island - Containment FCU Valve Replacement	188,211
17	Prairie Island - FCU Coil Replacement (Units 1 & 2)	474,549
18	Prairie Island - High Pressure Turbine Blade Rings (Unit 1)	137,912
19	Prairie Island - Low Pressure Turbine Replacement	6,822,212
20	Prairie Island - Spent Fuel Cask Procurement	490,079
21	Red Wing - AQCS	1,149,3[illegible]
22	Riverside - Install Diesel Generators for System Restoration Support	158,943
23	Riverside - Security Camera and Cardreader Additions	163,921
24	Sherco - Replace Rail Switch in Coal Yard	155,983
25	Sherco - Unit 1 & 2 Process Info & Control System	2,582,020
26	Sherco - Unit 3 Circ Water to Scrubber Make-up Pipe Addition	235,005
27	Sherco - Unit 2 Boiler Resurfacing	2,528,9[illegible]7
28	Sherco - Wet ESP Project Phase III	457,[illegible]48
29	Site #1 - Photovoltaics	318,8[illegible]1
30	Wilmarth - RDF Ash Storage Facility Construct Cell 3A & 3B	250,853
31	Small Production Projects	1,695,871
32		
33	TRANSMISSION PLANT	
34	Buffalo Ridge Sub - Feeder System	1,912,740
35	Eden Prairie Sub - Two 115Kv Breakers	815,870
36	Eden Prairie Sub - Transformer Capacity Addition	1,052,810
37	Forbes Sub - Manitoba - Minnesota Transmission Upgrade	410,976
38	Kohlman Lake Sub - Black Start Improvements	387,106
39	Kohlman Lake Sub - Install Ring Bus	3,510,355
40	Lawrence Sub - Install 34.5 Kv Source	128,682
41	Line 0725 - Lyon County Move for Highway Construction	121,241
42	Line 0727 - Relocate for S.D. Hwy Proj P0042(13)345	285,541
43	TOTAL	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 Demonstration (see Account 107 of the Uniform System of Accounts).

3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)
1	Line 0727 - Removal	$188,855
2	Line 0730 - Relocate for S.D. Hwy Proj # Im29-3(64)80	368,811
3	Line 0738 - New Wyoming-Hugo 115 Kv Line	350,020
4	Line 0806 - Aldrich Relocate Line	128,981
5	Line 0808 - Relocate Line City of Bloomington	186,433
6	Line 0811 - Reconductor Line	354,402
7	Line 0816 - 80th Street Project	286,779
8	Line 0825 - Restoration of Line Due to Storm of 07/27/95	281,640
9	Line 0827 - Dbl 115Kv	1,527,704
10	Line 0840 - Move Hiawatha Ave Between 7th & 24th St S	488,952
11	Line 0857 - Debif 115Kv Line	128,952
12	Line 0870 - Relocate Line	333,881
13	Line 0986 - Repair Damage from Storm of 6/29/96	185,855
14	Line 0987 - Repair Damage from Storm of 6/29/96	192,079
15	Line 5404 - Build WEH - Hastings with New 115Kv	117,254
16	Line 5503 - Split Rock - Cherry Creek Construct New Line	588,012
17	Line 5506 - Reterminate Line	278,973
18	Line 5519 - R/W and Land Chisago - Wyoming 115Kv Line	444,648
19	Line 5522 - 115Kv Line	396,325
20	Line 5523 - Chemolite - West Hastings 69Kv Convert to 115Kv	1,256,633
21	Line 5523 - Chemolite to West Hastings Easement Acquisition	109,961
22	Line 5524 - Rosemount - West Hastings Easement Acquistion	213,875
23	Line 5524 - West Hastings to Rosemount 115Kv Line	1,379,100
24	Line 5702 - 500Kv Foundation Rehabilitation	527,566
25	Moranville Sub - Replace Existing Breakers	317,428
26	Parkers Lake Sub - Install Shunt Reactor for Black Start	207,235
27	Rogers Lake Sub - Install Two 115Kv Line Breakers	1,426,825
28	Split Rock Sub - Install Breakers	160,892
29	West Gate Sub - Three 115Kv Breakers	1,181,942
30	West Gate Sub - 35Kv Fdr and 70Mva Xfmr	1,476,114
31	West Hastings Sub - 115Kv Station	2,586,763
32	Total Small Transmission Projects	1,844,370
33		
34	DISTRIBUTION PLANT	
35	Air Lake Sub - Upgrade Banks & Install 69Kv Bus-Tie Breaker	201,688
36	Airport Sub - Two-way Communication Project Expansion	103,896
37	Aldrich - Transformer #2	1,432,574
38	Aldrich - Two 115 Capacitor Banks	220,997
39	Aldrich Sub - Black Start Improvements	136,929
40	Aldrich Sub - Brkr & 1/2 Bus	7,592,895
41	Chemolite Sub - Install 115Kv Breakers	646,435
42	Elm Creek Sub - 115 Breaker for New Line	1,910,225
43	TOTAL	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

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 Demonstration (see Account 107 of the Uniform System of Accounts).

3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)
1	Elm Creek Sub - 345 Bus	$1,674,126
2	Elm Creek Sub - 70Mva Xfmr and 2-Fdrs	291,608
3	Elm Creek Sub - New 80Mvar 115Kv Capacitor	273,494
4	Faribault Sub - Additional 13.8Kv Capacity	239,551
5	Hugo Sub - Conversion of Hugo Sub to 115Kv	832,904
6	Hugo Sub - New 115/34.5 Kv Sub	1,893,189
7	Indiana Sub - Capacity Increase	470,020
8	Koch South Sub - Install Ring Bus	291,228
9	Lone Oak Sub - Convert to 115Kv	144,683
10	Lone Oak Sub - New Switchgear Building	722,813
11	Merriam Park Sub - Two-way Communication Project Expansion	162,210
12	Nine Mile Creek Sub - Six Feeders and Transformer	2,524,468
13	Sauk River Sub - New Sub	[illegible]1,777
14	Southtown Sub - Two-way Communication Project Expansion	146,896
15	Terminal Sub - Upgrade and Revise Relaying	130,227
16	West Sioux Falls Sub - 115Kv Line Breaker	456,737
17	Wilson Sub - Two-way Communication Project Expansion	114,384
18	Winona Sub - Third Bud Section and Two Feeders	105,573
19	Wyoming Sub - 115Kv Conversion	217,005
20	Small Distribution Projects	21,633,984
21		
22	GENERAL PLANT	
23	Chestnut Office - Small Tools and Equipment	227,627
24	Chestnut Office - Install Energy Efficient Lighting	143,383
25	Chestnut Office - Modular Furniture	435,680
26	Chestnut Office - Small Tools and Equipment	103,216
27	Chestnut Office - Renovation East of Front	626,390
28	Chestnut Office - Testing Lab Tools & Equipment	215,462
29	General Office - EPRI Implementation of DSA	200,184
30	General Office - SCC EMS Applications	371,653
31	General Office - SCC SCADA/AGC/PCM Replacement with OTS	8,319,245
32	Monticello Plant - Generation PC's	472,023
33	Ren Sq Office - Generation PC's	241,976
34	Shorewood Office - Mechanical System Upgrade	149,297
35	Total Small General Plant Projects	754,081
36		
37	GENERAL OFFICE PROJECTS	
38	Undistributed Overheads	(452,605)
39	Various Construction Projects - PAS Interim	902,427
40	Real Estate Taxes for Construction Work in Progress	3,049,740
41	Various Construction Projects - Payments Withheld	418,645
42		
43	TOTAL	$120,756,827

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

CONSTRUCTION OVERHEADS-ELECTRIC

1. List in column (a) the kinds of overheads according to the titles used by the respondent. Charges for outside professional services for engineering fees and management or supervision fees capitalized should be shown as separate items.

2. On page 218 furnish information concerning construction overheads.

3. A respondent should not report "none" to the page if no overhead apportionments are made, but rather should explain on page 218 the accounting procedures employed and the amounts of engineering, supervision and administrative costs, etc. which are directly charged to construction.

4. Enter on this page engineering, supervision, administrative, and allowance for funds used during construction, etc., which are first assigned to a blanket work order and then prorated to construction jobs.

Line No.	Description of Overhead (a)	Total Amount Charged for the Year (b)
1	Administrative and General Expense	$2,399,147
2	Engineering and Supervision - Prorate	15,008,290
3	Engineering and Supervision - Direct	1,608,974
4	Engineering and Supervision - Outside	5,338,417
5	Allowance for Funds Used During Construction	5,175,345
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46	TOTAL	$29,530,173

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. For each construction overhead explain: (a) the nature and extent of work, etc. the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.

2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Electric Plant Instructions 3(17) of the U.S. of A.

3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

* General Description of Construction Overhead Procedure (see P218.1)

Net of Tax Rate for Borrowed Funds =

Gross Rate for Borrowed Funds - (Gross Rate for Borrowed X Income Tax Rate)

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

For line 1(5), column (d) below, enter the rate granted in the last rate proceeding. If such is not available, use the average rate earned during the preceding three years.

1. Components of Formula (Derived from actual book balances and actual cost rates):

Line No.	Title (a)		Amount (b)	Capitalization Ratio (Percent) (c)		Cost Rate Percentage (d)
(1)	Average Short-Term Debt	S	$264,064			
(2)	Short-Term Interest				s	5.47%
(3)	Long-Term Debt	D	$1,297,006	45.37%	d	6.80%
(4)	Preferred Stock	P	$240,000	6.98%	p	5.18%
(5)	Common Equity	C	$1,639,605	47.65%	c	11.47%
(6)	Total Capitalization		$3,176,611	100%		
(7)	Average Construction Work in Progress Balance	W	$210,758			

2. Gross Rate for Borrowed Funds $s(\frac{S}{W}) + d(\frac{D}{D+P+C})(1 - \frac{S}{W})$ 6.15%

3. Rate for Other Funds

$[1 - \frac{S}{W}][p(\frac{P}{D+P+C}) + c(\frac{C}{D+P+C})]$ 1.50%

4. Weighted Average Rate Actually Used for the Year:

a. Rate for Borrowed Funds - 5.50%

b. Rate for Other Funds - 0

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

ADMINISTRATIVE AND GENERAL EXPENSES
This overhead has been established to accumulate the amount of Administrative and General expenses allocable to construction activities in the current year. Charges to this overhead are cleared to construction work orders on the basis of the ratio of the total expenses to the total construction charges, exclusive of leased and loaned property, station type transformers and regulators in reserve.

The major portion of Employee Pension and Benefits (account 926) allocable to construction has been cleared to construction work orders on the basis of direct construction labor through a labor loading factor.

Portions of accounts 920, 921, 922, 925, 926, and 408.1 were determined as applicable to construction.

ENGINEERING AND SUPERVISION PRORATE
This overhead has been established to accumulate the expenditures of the respondent's Engineering Department. The engineering and supervision charges are cleared to construction and removal work orders, on the basis of the ratio of the total engineering charges to the total construction and removal expense exclusive of all equipment classified as general plant, leased and loaned property, station type transformers and regulators in reserve, line transformers and regulators, meters, gas regulators, land rights and purchase of operating units or systems.

ENGINEERING AND SUPERVISION DIRECT
This overhead has accumulated the expenditures of the respondent's Engineering Department as applicable to certain specific projects. Engineering personnel time and expenses are cleared to construction on a time card basis.

ENGINEERING SERVICES - OUTSIDE
This overhead has been established to accumulate all expenditures made to other companies, firms, or individuals engaged by the respondent to plan, design, and prepare estimates, supervise, inspect, or give general advice and assistance in connection with construction and removal work. Charges to this overhead are cleared to specific construction and removal projects.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION
Allowance for funds used during construction is charged to capital projects when the period of construction will be over thirty days, such overheads cease when the project is placed in or ready for service. The rate for allowance for funds used during construction was 5.5%, effective January 1, 1996 through December 31, 1996.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 (d), 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	$2,642,592,831	$2,641,042,564		$1,550,267
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	234,281,830	234,281,830		
4	(413) Exp. of Elec. Plt.Leas.to Others	74,958			74,958
5	Transportation Expenses—Clearing	2,227,942	2,227,942		
6	Other Clearing Accounts	2,110,047	2,110,047		
7	Other Accounts (Specify):				
8					
9	Total Deprec. Prov. for Year (Enter Total of lines 3 thru 8)	$238,694,777	$238,619,819		$74,958
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	(45,458,861)	(45,458,861)		
12	Cost of Removal	(7,871,008)	(7,873,557)		2,549
13	Salvage (Credit)	14,622,109	14,622,109		
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	($38,707,760)	($38,710,309)		2,549
15	Other Debit or Cr.Items (Describe):	0			
16	Adjustments (Credit)	5,051,223	* 5,926,866		(875,643)
17	Balance End of Year (Enter Total of lines 1, 9, 14, 15, and 16)	$2,847,631,071	$2,846,878,940		$752,131

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

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)
18	Steam Production	811,834,620	811,834,620		
19	Nuclear Production	1,057,070,159	1,057,070,159		
20	Hydraulic Production-Conventional	4,234,830	4,234,830		
21	Hydraulic Production-Pumped Storage				
22	Other Production	71,147,440	71,147,440		
23	Transmission	243,389,513	243,187,193		202,320
24	Distribution	576,854,918	576,305,107		549,811
25	General	83,099,591	83,099,591		
26	TOTAL (Enter Total of lines 18 thru 25)	$2,847,631,071	$2,846,878,940		$752,131

< Page 219 Line 16 Column c >

Includes retirement adjustments of $(1,133,720); net transfer between utilities of $(4,897,665) and net changes in Electric Retirement Work In Progress of $980,162.

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NONUTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of nonutility property included in Account 121.

2. Designate with a double asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.

3. Furnish particulars (details) concerning sales, purchases, or transfers of Nonutility Property during the year.

4. List separately all property previously devoted to public service and give date of transfer to Account 121, Nonutility Property.

5. Minor Items (5% of the Balance at the End of the Year), for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service(line 44), or(2) other nonutility property (line 45).

Line No.	Description and Location (a)	Balance of Beginning of Year (b)	Purchases, Sales, Transfers, etc. (c)	Balance at End of Year (d)
1	Property Previously Devoted To Public Service			
2				
3	1958 Underground Conduit and Manholes Acq Fr T.C.R.T.	71,925		71,925
4	1958 Formerly Fargo Diesel Plant Site	200,954	(200,954)	0
5	1987 Portion of 69Kv Line No. 0708	90,210		90,210
6	1989 Portion of 69Kv Line No. 0734	33,614		33,614
7	1994 Portion of 69Kv Line No. 0734	180,062		180,062
8				
9				
10				
11				
12	Other Nonutility Property			
13				
14	1976 Easements - Line 0854	49,542		49,542
15	1968-1972 Easements - Line 0864	44,490		44,490
16	1980 Easements - Line 0985	60,533		60,533
17	1976 Easements - Line 5702	63,053		63,053
18	1982 Wescott Propane Plant - House & Garage	82,000		82,000
19	1983 Easements - Line 0871	90,118		90,118
20	1983 Cedar Lake Substation Site	173,629		173,629
21	1984-1986 Sherburne County - House & Out Buildings	324,000		324,000
22	1992 Shady Oak Substation Site	640,454	(640,454)	0
23	1985 Refuse Derived Fuel Facility - Elk River/Becker	30,152,517	52,061	30,204,578
24	1993 CNG Compressor - Reinforced Thermo Products, Inc	40,532		40,532
25	1993 Liberty Paper Steam Line	4,849,716	387,895	5,237,611
26	1992-1996 Ultra Power Tools	82,232	28,537	110,769
27	1991 Grand Forks Boiler Plant	121,421		121,421
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44	Minor Item Previously Devoted to Public Service	106,506		106,506
45	Minor Items-Other Nonutility Property	357,596	(44,472)	313,124
46	TOTAL	$37,815,104	($417,387)	$37,397,717

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 thereunder 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	NORTHERN STATES POWER CO. (WIS)			
2	Common Stock-par $100 per share			
3	* per share 1938-1988			96,750,946
4	Undistributed subsidiary			
5	earnings since acquisition			219,077,320
6	SUBTOTAL			315,828,266
7				
8				
9	UNITED POWER AND LAND COMPANY			
10	Common Stock-par $100 per share			4,020,000
11	Undistributed subsidiary			
12	earnings since acquisition			2,076,285
13	SUBTOTAL			6,096,285
14				
15				
16	CORMORANT CORPORATION			
17	Common Stock-par $10 per share			1,275,000
18	Undistributed subsidiary			
19	earnings since acquisition			(602,193)
20	SUBTOTAL			672,807
21				
22				
23	FIRST MIDWEST AUTO PARK, INC.			
24	Common Stock-par $1.00 per share			730,570
25	Undistributed subsidiary			
26	earnings since acquisition			1,172,908
27	SUBTOTAL			1,903,478
28				
29				
30	NRG ENERGY, INC.			
31	Notes Receivable - Variable rate (5.40% - 6.75%)	12/31/93	12/01/06	8,405,408
32	Common Stock-par $100 per share			271,028,881
33	Undistributed subsidiary			
34	earnings since acquisition			46,307,701
35	SUBTOTAL			325,741,990
36				
37	ELOIGNE COMPANY			
38	Common Stock-no par value			22,650,000
39	Undistributed subsidiary			
40	earnings since acquisition			2,638,052
41	SUBTOTAL			25,288,052
42	TOTAL Cost of Account 123.1 $		TOTAL	

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)(Continued)

4. For any securities, notes, or accounts that were pledged, designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.

5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.

6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.

7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).

8. Report on Line 42, column (a) the total cost of Account 123.1.

Equity in Subsidiary Earnings for Year (e)	Revenues For Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
		96,750,946		3
				4
38,697,104		* 231,504,804		5
38,697,104	0	328,255,750	0	6
				7
				8
				9
		4,020,000		10
				11
536,376		2,612,661		12
536,376	0	6,632,661	0	13
				14
				15
				16
		1,275,000		17
				18
(910)		* (1,273,103)		19
(910)	0	1,897	0	20
				21
				22
				23
		730,570		24
				25
257,767		1,430,675		26
257,767	0	2,161,245	0	27
				28
				29
				20
		* 7,811,086		31
		* 351,028,881		32
				33
19,977,793		66,285,494		34
19,977,793	0	425,125,461	0	35
				36
				37
		* 29,800,000		38
				39
3,296,365		5,934,417		40
3,296,365	0	35,734,417	0	41
				42

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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 thereunder 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	VIKING GAS TRANSMISSION COMPANY			
2	Common Stock-par $5.00 per share			13,075,171
3	Undistributed Subsidiary			
4	earnings since acquisition			3,245,075
5	SUBTOTAL			16,320,246
6				
7				
8	CENERPRISE, INC.			
9	Common Stock-no par value			18,603,897
10	Undistributed subsidiary			
11	earnings since acquisition			(1,697,846)
12	SUBTOTAL			16,906,051
13				
14				
15	MESCALERO Fuel Storage, LLC			
16	Equity Investment			379,762
17	Undistributed subsidiary			
18	earnings since acquisition			0
19	SUBTOTAL			379,762
20				
21				
22	NORTHERN POWER WISCONSIN CORPORATION			
23	Common Stock-par $.01 per share			1,000
24	Undistributed Subsidiary			
25	earnings since acquisition			0
26	SUBTOTAL			1,000
27				
28				
29	SEREN INNOVATIONS			
30	Undistributed Subsidiary			
31	earnings since acquisition			0
32	SUBTOTAL			0
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	TOTAL Cost of Account 123.1 $ 524,516,595		TOTAL	$709,137,937

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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 for 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
		13,075,171		2
				3
2,524,981		* 3,670,056		4
2,524,981	0	16,745,227	0	5
				6
				7
				8
		* 27,836,027		9
				10
(8,526,312)		(10,224,158)		11
(8,526,312)	0	17,611,869	0	12
				13
				14
				15
		* 640,585		16
				17
0		0		18
0	0	640,585	0	19
				20
				21
				22
		1,000		23
				24
0		0		25
0	0	1,000	0	26
				27
				28
				29
				20
(56,804)		(56,804)		31
(56,804)	0	(56,804)	0	32
				33
				34
				35
				36
				37
				38
				39
				40
				41
$56,706,360	0	$832,853,308	0	42

< Page 224 Line 3 Column a >

As of January 2, 1938, incident to recapitalization of Northern States Power Company (Delaware) and Northern States Power Company (Wisconsin) respondent acquired 149,472 shares of common stock of Northern States Power Company (Wisconsin). This acquisition was effective pursuant to SEC Order No. 46-102 dated December 28, 1938, Pub. Serv. Comm. of Wis. Docket No. 2-SB-97 dated May 6, 1938, and Pub. Serv. Comm. of Wis. No. 2-SB-116 dated December 19, 1938.

Subsequent acquisitions and commission approvals are as follows:

Year	Shares Acquired	Name of Commission	Date of Authorization	Case or Docket No.
1939	25,327	SEC	March 21, 1939	32-132
		PSC of Wis	March 9, 1939	2-SB-119
1947	5,201	SEC	April 11, 1947	70-1490-1
		PSC of Wic	April 22, 1947	2-SB-282
1948	60,000	SEC	June 30, 1948	70-1859
		PSC of Wis	June 15, 1948	2-SB-331
1949	15,000	SEC	Oct. 31, 1949	70-2247
		PSC of Wis	Oct. 18, 1949	2-SB-378
1950	30,000	SEC	July 14, 1950	70-2427
		PSC of Wis	June 30, 1950	2-SB-418
1954	40,000	SEC	April 2, 1954	70-3221
		PSC of Wis	Mar. 25, 1954	2-SB-555
1957	56,929	FPC	Oct. 25, 1957	E-6774
		PSC of Wis	Oct. 18, 1957	2-SB-694
1958	1,855	FPC	Sep. 12, 1958	E-6834
1973	127,928	*PSC of Wis	Mar. 22, 1973	2-SB-1274
1976	188,288	**PSC of Wis	July 1, 1976	4220-SB-2
1987	124,000	PSC of Wis	Dec. 30, 1986	4220-SB-103
1988	38,000	PSC of Wis	Dec. 22, 1987	4220-SB-106
		PSC of Wis	Jan. 7, 1988	
		PSC of MI	Dec. 22, 1987	U-8937

* 33-1/3% stock dividend
** Approximately 3 for 2 stock dividend

< Page 225 Line 5 Column g >

In 1996, Undistributed subsidiary earnings for Northern States Power Company (Wis) was reduced by $685,460 due to subsidiary appropriation of retained earnings.

Dividends of $[illegible]5,584,160 were paid to the Company by Northern States Power Company (Wis) in 1996.

< Page [illegible] Line [illegible] Column g >

Dividends of $670,000 were paid to the Company by Cormorant Corporation in 1996.

< Page 225 Line 31 Column g >

$594,322 was transferred to Notes Receivable-Current Portion, FERC account 145 in 1996.

< Page 225 Line 32 Column g >

Equity Contribution was made in 1996 totaling $80,000,000.

< Page 225 Line 38 Column g >

Equity Contribution was made in 1996 totaling $7,150,000.

< Page 225.1 Line 4 Column g >

Dividends of $2,100,000 were paid to the Company by Viking Gas Transmission Company in 1996.

< Page 225.1 Line 9 Column g >

Equity Contribution was made in 1996 totaling $9,232,130.

< Page 225.1 Line 16 Column g >

Equity Contribution was made in 1996 totaling $260,823.

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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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)	$23,796,377	$21,516,095	
2	Fuel Stock Expenses Undistributed (Account 152)	1,432,267	1,308,399	
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	30,852,407	37,561,918	All Utilities
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	46,937,083	44,173,090	All Utilities
8	Transmission Plant (Estimated)	1,152,941	1,021,393	All Utilities
9	Distribution Plant (Estimated)	11,234,264	14,434,902	All Utilities
10	Assigned to - Other	2,176,427	1,112,590	All Utilities
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	$92,353,122	$98,303,893	
12	Merchandise (Account 155)		1,482,582	
13	Other Materials and Supplies (Account 156)	396,202	472,717	
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)			
15	Stores Expense Undistributed (Account 163)	(32,988)	346,948	
16	Liquified Natural Gas Stored			
17	(Account 164)	12,023,226	14,409,161	
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	$129,968,206	$137,839,795	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 eligble 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)

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	1997 No. (d)	1997 Amt. (e)
01	Balance-Beginning of Year	48,705.00	0	14,517.00	0
02 03 04	Acquired During Year: Issued (Less Withheld Allow.)	0	0	0	0
05	Returned by EPA	0	0	0	0
06 07 08	Purchases/Transfers:				
09					
10					
11					
12					
13					
14					
15	Total				
16 17 18	Relinquished During Year: Charges to Account 509	13,923.84	0	0	0
19	Other:	0	0	0	0
20					
21 22	Cost of Sales/Transfers: Wisconsin Electric Power	12.00			
23	Wisconsin Electric Power	3.00			
24					
25					
26					
27					
28	Total	15.00			
29	Balance-End of Year	* 34,766.16	0	14,517.00	0
30 31 32	Sales: Net Sales Proceeds (Assoc. Co.)	0	0	0	0
33	Net Sales Proceeds (Other)	15.00	2,145	0	0
34	Gains	15.00	2,145	0	0
35	Losses	0	0	0	0
	Allowances Withheld (Account 158.2)				
36	Balance-Beginning of Year	112.00	0	112.00	0
37	Add: Withheld by EPA	0	0	0	0
38	Deduct: Returned by EPA	0	0	0	0
39	Cost of Sales	112.00	0	0	0
40	Balance-End of Year	0	0	112.00	0
41 42 43	Sales: Net Sales Proceeds (Assoc. Co.)	0	0	0	0
44	Net Sales Proceeds (Other)	112.00	7,632	0	0
45	Gains	112.00	7,632	0	0
46	Losses				

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

Allowances (Accounts 158.1 and 158.2) (Continued)

issued allowances. Report withheld portions lines 36-40

6. Report on lines 5 allowances returned by the EPA. Report on line 39 the EPA's sales of the withheld allowances. Report on lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.

7. Report on lines 8-14 the names of vendors/transferors of allowances acquired 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 and 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 & 43-46 the net sales proceeds and gains or losses from allowance sales.

1998		1999		Future Years		Totals		
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	Line No.
14,517.00	0	14,517.00	0	1,747,358.00	0	1,839,614.00	0	01
0	0	0	0	84,714.00	0	84,714.00	0	02 03 04
0	0	0	0	0	0	0	0	05
								06 07 08
								09
								10
								11
								12
								13
								14
						0	0	15
0	0	0	0	0	0	13,923.84	0	16 17 18
0	0	0	0	0	0	0	0	19
						0	0	20
						12.00	0	21 22
						3.00		23
								24
								25
								26
								27
						15.00	0	28
14,517.00	0	14,517.00	0	1,832,072.00	0	1,910,389.16	0	29
0	0	0	0	0	0	0	0	30 31 32
0	0	0	0	0	0	15.00	2,145	33
0	0	0	0	0	0	15.00	2,145	34
0	0	0	0	0	0	0	0	35
[redacted]								
112.00	0	112.00	0	44,049.46	0	44,497.46	0	36
0	0	0	0	2,463.00	0	2,463.00	0	37
0	0	0	0	0	0	0	0	38
0	0	0	0	944.63	0	1,056.63	0	39
112.00	0	112.00	0	45,567.83	0	45,903.83	0	40
0	0	0	0	0	0	0	0	41 42 43
0	0	0	0	944.63	63,451	1,056.63 *	71,083	44
0	0	0	0	944.63	63,451	1,056.63	71,083	45
								46

< Page 228 Line 29 Column b >

All allowances are valued at $0 from EPA.

< Page 229 Line 44 Column m >

The amount includes $10,810 of proceeds received and transferred to Northern States Power Co (WI) under an interchange agreement between the companies dated Sept. 17, 1984. The amount excludes $929 of proceeds originally received by Northern States Power Co (WI) and transferred to Northern States Power Co (MN).

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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other accounts).

2. For regulatory assets being amortized, show period of amortization in column (a).

3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Debits (b)	CREDITS Account Charged (c)	CREDITS Amount (d)	Balance at End of Year (e)
1	UNAMORTIZED CONSERVATION & ENERGY MANAGEMENT				
2	PROGRAM COSTS (generally amortized over the				
3	five-year period following expenditure):				
4					
5	Electric Operations	189,104,774	108	1,232	82,258,708
6			131	67,125	
7			142	528,075	
8			143	23,144	
9			155	1,842,750	
10			165	1,452	
11			182.3	8,774,841	
12			184	35,262	
13			184.1	161,127	
14			184.2	25,209,679	
15			186	16,771	
16			232	4,471,513	
17			419.1	2,901,969	
18			432	1,620,526	
19			456	42,464,999	
20			557.1	529	
21			908.1	101,607,478	
22			910	440	
23					
24	Gas Operations	12,864,929	131	5,746	2,853,304
25			142	349,048	
26			184.1	1,582	
27			184.2	4,012	
28			186	8,043	
29			232	59,056	
30			419.1	225,328	
31			432	17,521	
32			495	2,450,808	
33			908	5,709	
34			908.1	10,225,443	
35					
36	UNRECOVERED ENVIRONMENTAL COSTS:				
37					
38	DOE Decommissioning & Decontamination Assessment	1,217,850	518	4,034,654	40,916,597
39	(amortized over period 1993-2008)				
40					
41	Gas Site Remediation	930,120	232	12,711	4,240,212
42					
43					
44	TOTAL				

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other accounts).

2. For regulatory assets being amortized, show period of amortization in column (a).

3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Debits (b)	CREDITS Account Charged (c)	CREDITS Amount (d)	Balance at End of Year (e)
1	TAX RELATED COST DEFERRALS:				
2					
3	Net-of-Tax AFUDC Adjustments-FASB 109	1,886,000	282	8,492,000	129,398,000
4	(generally amortized over related plant lives)		283	2,432,000	
5					
6					
7	IRS and State Interest Deferrals				1,608,533
8					
9					
10	Sales and Use Tax Deferrals	814,793	107	122,968	108,447
11			131	601,025	
12			143	78,261	
13					
14					
15	EMPLOYEE BENEFIT COST DEFERRALS:				
16					
17	Accrued Costs-FASB 106 (in Minnesota, amortized	516,667	253	2,376,666	0
18	over 1994-1996)		926	3,985,875	
19					
20					
21	SOUTH DAKOTA RATEMAKING DIFFERENCES:	132,000	419.1	279,000	5,382,000
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44	TOTAL	$207,467,133	[redacted]	$225,496,368	$266,765,801

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

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 items (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDIT Account Charged (d)	CREDIT Amount (e)	Balance at End of Year (f)
1	LONG-TERM ACCOUNTS RECEIVABLE:					
2						
3	Tax Refund Claims Paid	53,756,291	820,110	*	5,070,604	49,505,797
4	(including interest)					
5						
6	IPP Power Contract Billing	2,480,410	139,494	253	15,953	2,603,951
7	Adjustments					
8						
9	Energy Loan & Other Programs	4,024,827	22,094,448	*	19,947,300	6,171,975
10	Administered for St. Agencies					
11						
12	Damage Claims Against other	4,905,524	3,308,543	*	6,147,351	2,066,716
13	Parties					
14						
15	Other	37,289	22,594	*	31,911	27,972
16						
17						
18	* LONG-TERM PREPAYMENTS &					
19	DEFERRED CHARGES:					
20						
21	Prepaid Pension Exp - FAS87	6,556,000	23,572,000	253	20,267,035	9,860,965
22						
23	Prepaid Regulatory Fees	471,729	590,714	928	471,729	590,714
24						
25	Securities Registration Costs	122,587				122,587
26						
27	Deferred Merger Costs	13,889,693	10,914,789	*	264,317	24,540,165
28						
29	Deferred Litigation Costs	0	3,979,129	184.1	391,908	3,587,221
30						
31	Prepaid Decommissioning Costs	0	2,073,023		0	2,073,023
32						
33	Other	0	21,300	151	23,810	(2,510)
34						
35						
36	DEBITS NOT ELSEWHERE PROVIDED					
37	FOR:					
38						
39	Items for which Final	25,703	500,629	*	208,216	318,116
40	Disposition is Uncertain					
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress	449,680				1,044,121
48	DEFERRED REGULATORY COMM. EXPENSES (See pages 350-351)					
49	TOTAL	$86,719,733				$102,510,813

< Page 233 Line 3 Column d >

Accounts charged include:	131	$4,762,706
	419	307,898
	TOTAL	$5,070,604

< Page 233 Line 9 Column d >

Accounts charged include:	142	$9,815,521
	184.2	1,055,153
	186	1,977,970
	232	7,098,656
	TOTAL	$19,947,300

< Page 233 Line 12 Column d >

Accounts charged include:	107	$1,576,380
	131	1,578,257
	143	8,971
	184	17
	184.1	423
	232	879,075
	426.5	1,292,415
	512	458
	513	26,862
	571	3,613
	925	780,880
	TOTAL	$6,147.351

< Page 233 Line 15 Column d >

Accounts charged include:	143	$25,058
	416	6,853
	TOTAL	$31,911

< Page 233 Line 18 Column a >

Includes some amounts which are classified as current assets under GAAP & SEC rules.

< Page 233 Line 27 Column d >

Accounts charged include:	131	$4,967
	146	1,289
	211	2,225
	232	255,836
	TOTAL	$264,317

< Page 233 Line 39 Column d >

Accounts charged include:	142	$205,742
	232	2,474
	TOTAL	$208,216

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2		* $299,871,044	$318,659,092
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	$299,871,044	$318,659,092
9	Gas		
10		* 16,540,240	17,194,66
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	$16,540,240	$17,194,661
17	Other Non Operating	* 16,408,640	15,898,771
18	TOTAL (Acct 190)(Total of lines 8,16 and 17)	$332,819,924	$351,752,524

NOTES

< Page 234 Line 2 Column b >

ELECTRIC	Bal at Beg of Year	Bal at End of Year
Accrued Vacation Paid	6,126,678	6,425,437
Ad Valorem Tax Coal	55,100	133,833
Avoided Tax Interest	12,870,172	13,367,177
Bad Debts	1,185,114	3,030,915
Board of Directors Retiremnt Ben	1,006,272	1,010,173
Coal Mine Reclam. Reserve	1,496,396	525,120
Customer Advances	667,355	520,257
Deferred Connection Fees	7,944,880	8,558,855
Early Retirement Obligation	4,182,034	4,182,034
End of Life Nuc. Fuel Amort.	4,410,409	5,247,782
Environmental Remediation	577,293	555,869
FAS 109-Effect of Rate Changes	29,930,061	33,632,247
FAS 109-ITC Grossup	83,514,195	78,150,155
Low Income Discount Program	0	3,239,657
Low Level Radiation Waste	10,286	6,598
Medical Deduction-Self Insured	1,526,414	1,536,975
Nuc. Fuel Disp.-Prairie Island	7,275,443	2,535,593
Nuc. Plant-Decommissioning Prov.	105,210,265	112,028,104
Pending Lawsuits	1,490,559	695,564
Photo Voltaic	0	(897)
Post Employment Benefits-FAS 112	3,870,948	3,590,500
Post Retirement Benefits-FAS 106	12,113,174	18,124,862
Regulatory Liab-SMMPA Settlement	0	3,353,386
Regulatory Liab-Tax Interest	136,125	(26)
Sale of Emission Allowances	0	134,094
Saver Switches- MN, ND, SD	3,123,570	5,664,919
Severance Accrual	3,593,424	2,523,836
Trust Fund Interest Capitalized	888,450	773,060
Unbilled Revenues	1,653,375	4,126,521
Unfunded Pension Costs	4,867,090	4,867,090
Workers Compensation	145,962	119,402
	299,871,044	318,659,092

< Page 234 Line 10 Column b >

GAS	Bal at Beg of Year	Bal at End of Year
Accrued Vacation Paid	629,056	659,286
Avoided Tax Interest	276,818	188,729
Bad Debts	104,207	284,059
Board of Directors Retiremnt Ben	98,257	98,637
Deferred CIAC-Surcharge	168,976	333,209
Deferred Connection Fees	2,338,049	2,535,620
Early Retirement Obligation	429,429	429,429
Environmental Remediation	56,370	54,282
FAS 109-Effect of Rate Changes	2,450,939	2,827,753
FAS 109-ITC Grossup	6,619,805	6,073,845
Lower of Cost or Market on Gas Inv.	544,202	506,334
Medical Deduction-Self Insured	156,734	157,803
Pending Lawsuits	127,420	49,957
Post Employment Benefits-FAS 112	397,480	369,103
Post Retirement Benefits-FAS 106	1,244,892	1,853,189
Regulatory Liability-Tax Interest	13,292	26
Severance Accrual	369,553	261,326
Unfunded Pension Costs	499,774	499,774
Workers Compensation	14,987	12,300
	16,540,240	17,194,661

< Page 234 Line 17 Column b >

NONUTILITY	Bal at Beg of Year	Bal at End of Year
Bad Debts	0	354,988
Compensation Exp-Stock Option Plan	361,472	398,397
Deferred Compensation Plan Balances	10,112,467	10,702,940
Executive Long Term Incentive Plan	403,587	13,546
Rate Refund	39,207	51,666
Environmental & Regulatory Reserves	5,491,907	4,377,234
	16,408,640	15,898,771

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

CAPITAL STOCK (Accounts 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 Exchange (a)	Number of Shares Authorized By Charter (b)	Par or Stated Value Per Share (c)	Call Price at End of Year (d)
1	Cumulative Preferred Stock:	7,000,000		
2	$3.60 Series		$100.00	$103.75
3	$4.08 Series		$100.00	$102.00
4	$4.10 Series		$100.00	$102.50
5	$4.11 Series		$100.00	$103.73
6	$4.16 Series		$100.00	$103.75
7	$4.56 Series		$100.00	$102.47
8	$6.80 Series		$100.00	$103.19
9	$7.00 Series		$100.00	$103.20
10	Variable Rate Series A		$100.00	$100.00
11	Variable Rate Series B		$100.00	$100.00
12				
13	* TOTAL_PREFERRED STOCK	7,000,000		
14				
15	* Common Stock	160,000,000	$2.50	
16				
17	Leveraged Common Stock held by			
18	Employee Stock Ownership Plan			
19				
20	TOTAL_COMMON STOCK	160,000,000		
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36	< Page 250 Line 13 Column a >			
37	New York Stock Exchange except Series A and B.			
38				
39				
40	< Page 250 Line 15 Column a >			
41	New York Stock Exchange, Chicago Stock Exchange			
42	and Pacific Stock Exchange.			

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

CAPITAL STOCK (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 noncumulative.

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
275,000	27,500,000					2
150,000	15,000,000					3
175,000	17,500,000					4
200,000	20,000,000					5
100,000	10,000,000					6
150,000	15,000,000					7
200,000	20,000,000					8
200,000	20,000,000					9
300,000	30,000,000					10
650,000	65,000,000					11
						12
2,400,000	240,000,000	0	0	0	0	13
						14
69,063,712	172,659,279					15
						16
						17
		381,313	19,091,577			18
						19
69,063,712	172,659,279	381,313	19,091,577	0	0	20
						21
						22
						23
						24
						25
						26
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						42

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

CAPITAL STOCK SUBSCRIBED, CAPITAL STOCK LIABILITY FOR CONVERSION, PREMIUM ON CAPITAL STOCK, AND INSTALLMENTS RECEIVED ON CAPITAL STOCK (Accounts 202 and 205, 203 and 206, 207, 212)

1. Show for each of the above accounts the amounts applying to each class and series of capital stock.
2. For Account 202, Common Stock Subscribed, and Account 205, Preferred Stock Subscribed, show the subscription price and the balance due on each class at the end of year.
3. Describe in a footnote the agreement and transactions under which a conversion liability existed under Account 203, Common Stock Liability for Conversion, or Account 206, Preferred Stock Liability for Conversion, at the end of the year.
4. For Premium on Account 207, Capital Stock, designate with a double asterisk any amounts representing the excess of consideration received over stated values of stocks without par value.

Line No.	Name of Account and Description of Item (a)	Number of Shares (b)	Amount (c)
1	Account 207-Premium on Capital Stock		
2			
3	Common Stock	22,178,286	9,860,222
4			
5	Excess of consideration received over par value on Common Stock issued		
6			
7	Year:		
8	1952	2,217,932	6,099,313
9	1954	2,439,712	11,032,995
10	1956	1,341,840	7,908,071
11	1957	352,600	1,674,850
12	1958	30,608	229,560
13	1959	1,904,066	16,184,561
14	1960	379,336	3,224,356
15	1964	35,948	539,220
16	1965	1,544,016	21,616,224
17	1969	2,161,622	23,777,842
18	1970	3,458,596	28,533,417
19	1972	3,804,456	35,282,538
20	1973	4,184,902	40,802,795
21	1974	4,600,000	28,750,000
22	1975	3,598,714	32,487,831
23	1976	4,336,954	41,706,787
24	1977	495,958	5,980,264
25	1978	874,670	8,726,553
26	1979	1,341,418	12,013,023
27	1980	386,516	2,995,959
28	1982	563,010	6,321,599
29	1983	616,116	8,631,736
30	1984	641,316	10,603,925
31	1985	592,244	12,096,414
32	1992	56,956	1,869,212
33	1993	4,281,217	177,021,848
34	1994	42,567	2,315,928
35	1995	1,253,790	52,703,181
36	1996	887,778	40,309,230
37			
38	Reduction of premium associated with retirement of Treasury		
39	Stock in 1991	(1,539,432)	(9,058,701)
40			
41			
42			
43			
44			
45			
46	TOTAL		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Northern States Power Company (Minnesota)	(1) [x] An Original (2) [ ] A Resubmission		Dec. 31, 1996

CAPITAL STOCK SUBSCRIBED, CAPITAL STOCK LIABILITY FOR CONVERSION, PREMIUM ON CAPITAL STOCK, AND INSTALLMENTS RECEIVED ON CAPITAL STOCK (Accounts 202 and 205, 203 and 206, 207, 212)

1. Show for each of the above accounts the amounts applying to each class and series of capital stock.
2. For Account 202, Common Stock Subscribed, and Account 205, Preferred Stock Subscribed, show the subscription price and the balance due on each class at the end of year.
3. Describe in a footnote the agreement and transactions under which a conversion liability existed under Account 203, Common Stock Liability for Conversion, or Account 206, Preferred Stock Liability for Conversion, at the end of the year.
4. For Premium on Account 207, Capital Stock, designate with a double asterisk any amounts representing the excess of consideration received over stated values of stocks without par value.

Line No.	Name of Account and Description of Item (a)	Number of Shares (b)	Amount (c)
1	Excess of consideration received over stated value of stocks		
2	originally issued without par value:		
3			
4	Premium of $2.75 per share on Cumulative Preferred Stock, $3.60 Series	46,240	127,160
5	Premium of $0.4278 per share on Cumulative Preferred Stock,		
6	$4.10 Series	175,000	74,865
7			
8	Excess of stated value over par value arising pursuant to amended		
9	Articles of Incorporation on May 2, 1951, whereby the Preferred Stock		
10	was changed from shares without par value to shares having a par		
11	value of $100 each:		
12			
13	Cumulative Preferred Stock, $4.10 Series	175,000	52,500
14			
15	Premium on Cumulative Preferred Stock issued and sold:		
16			
17	17 cents per share, $4.08 Series, April 1954	150,000	25,500
18	12.6 cents per share, $4.11 Series, August 1954	200,000	25,200
19	6 cents per share, $4.16 Series, March 1956	100,000	6,000
20	19 cents per share, $4.56 Series, July 1964	150,000	28,500
21	18 cents per share, $6.80 Series, May 1968	200,000	36,000
22	46.9 cents per share, $7.00 Series, January 1969	200,000	93,800
23			
24			
25			
26	Account 212-Installments Received on Capital Stock		
27			
28	Installments Received on Capital Stock		80,731
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			
45			
46	TOTAL	70,459,952	$642,791,009

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

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 debt 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	Account 211 - Miscellaneous Paid-In Capital	
2		
3	Expenses incurred for the issuance of new common stock (includes $226,619 incurred for	(3,579,611)
4	current year)	
5		
6	Subtotal	(3,579,611)
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
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26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	($3,579,611)

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Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

LONG-TERM DEBT (Accounts 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	1997, October 1 - 5.875% / LIBOR	100,000,000	993,4[illegible]
6			195,000 D
7			
8	1999, February 1 - 5.50% / LIBOR	200,000,000	1,016,938
9			350,000 D
10			
11	2000, December 1 - 5.75%	100,000,000	1,017,166
12			517,000 D
13			
14	2001, October 1 - 7.875%	150,000,000	1,018,097
15			600,000 D
16			
17	2002, March 1 - 7.375%	50,000,000	550,036
18			(150,000) P
19			
20	2003, February 1 - 7.50%	50,000,000	428,694
21			(375,000) P
22			
23	2003, April 1 - 6.375%	80,000,000	858,430
24			320,000 D
25			
26	2005, December 1 - 6.125%	70,000,000	746,598
27			644,700 D
28			
29			
30	2025, July 1 - 7.125%	250,000,000	1,898,288
31			2,330,000 D
32			
33	TOTAL		

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

LONG-TERM DEBT (Accounts 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 amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt - Credit.

12. In a footnote, give explanatory particulars (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) principal repaid during year. Give Commission authorization numbers and dates.

13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.

14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.

15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.

16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
10/01/92	10/01/97	10/01/92	10/01/97	100,000,000	5,747,237	5
						6
						7
02/01/94	02/01/99	02/01/94	02/01/99	200,000,000	10,730,446	8
						9
						10
12/01/93	12/01/00	12/01/93	12/01/00	100,000,000	5,750,000	11
						12
						13
10/01/94	10/01/01	10/01/94	10/01/01	150,000,000	11,812,500	14
						15
						16
03/01/72	03/01/02	03/01/72	03/01/02	50,000,000	3,687,500	17
						18
						19
02/01/73	02/01/03	02/01/73	02/01/03	50,000,000	3,750,000	20
						21
						22
04/01/93	04/01/03	04/01/93	04/01/03	80,000,000	5,100,000	23
						24
						25
12/01/93	12/01/05	12/01/93	12/01/05	70,000,000	4,287,500	26
						27
						28
						29
07/01/95	07/01/25	07/01/95	07/01/25	250,000,000	17,812,500	30
						31
						32
						33

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

LONG-TERM DEBT (Accounts 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	Burnsville Pollution Control Series C - 6.2%	$8,800,000	$279,847
2			
3	Pollution Control Series J, K and L - Variable	13,700,000	788,833
4			
5	Ramsey & Washingtion County Resource Recovery Series I - Variable	27,700,000	611,625
6			
7	SUBTOTAL - ACCOUNT 221	1,100,200,000	14,639,720
8			
9			
10	ACCOUNT 224 - OTHER LONG-TERM DEBT:		
11			
12	Public Improvements	1,691,819	
13			
14	Genstar - 9.00%	9,484	
15			
16	Mankato Service Center - 10.00%	441,980	
17			
18	ESOP Loan - Variable	15,000,000	
19			
20	ESOP Loan - Variable	15,000,000	
21			
22			
23	GUARANTY AGREEMENTS - POLLUTION CONTROL FINANCING AT AVERAGE INTEREST RATES		
24			
25	Red Wing - 5.69%	28,750,000	346,087
26			
27	1975 Monticello - 7.40%	3,500,000	97,713
28			
29	1973 Monticello - 5.41%	7,600,000	141,625
30			39,000 D
31			
32	Sioux Falls - 5.78% - Industrial Developement Revenue Bond	940,000	41,652
33	TOTAL		

LONG-TERM DEBT (Accounts 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 amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt - Credit.

12. In a footnote, give explanatory particulars (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) principal repaid during year. Give Commission authorization numbers and dates.

13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.

14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.

15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.

16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
03/01/76	03/01/96	03/01/76	03/01/96	0	90,933	1
						2
07/01/81	03/01/11	07/01/81	03/01/11	13,700,000	482,634	3
						4
12/01/84	12/01/06	12/01/84	12/01/06	19,800,000	1,352,152	5
						6
				1,083,500,000	70,603,402	7
						8
						9
						10
						11
				48,051	98,971	12
						13
02/17/82	12/27/96			0	854	14
						15
09/01/91	08/01/03			170,212	5,284	16
						17
04/03/95	*			4,358,081	443,323	18
						19
09/18/96	*			13,213,330	74,019	20
						21
						22
						23
						24
05/01/73	*	05/01/73	05/01/03	23,750,000	1,361,833	25
						26
07/01/75	02/01/03	07/01/75	02/01/03	3,500,000	259,000	27
						28
02/01/73	*	02/01/73	02/01/03	5,500,000	298,781	29
						30
						31
10/01/73	*	10/01/73	12/01/98	135,000	10,440	32
[redacted]						33

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

LONG-TERM DEBT (Accounts 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	NON-COLLATERALIZED POLLUTION CONTROL		
2			
3	1985 Anoka County Series - 7.00%	29,750,000	605,664
4			
5	1987 Becker - 7.25%	9,000,000	257,088
6			
7	1989A Becker Pollution Control - 6.80%	60,000,000	784,380
8			1,050,000 D
9			
10	1992A Becker Pollution Control - Variable	27,900,000	242,682
11			
12	1993A Becker Pollution Control - Variable	50,000,000	247,188
13			
14	1993B Becker Pollution Control - Variable	50,000,000	228,326
15			
16			
17	* SUBTOTAL - ACCOUNT 224	299,583,283	4,081,405
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	$1,399,783,283	$18,721,125

LONG-TERM DEBT (Accounts 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 amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt - Credit.

12. In a footnote, give explanatory particulars (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) principal repaid during year. Give Commission authorization numbers and dates.

13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.

14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.

15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.

16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
12/01/85	12/01/08	12/01/85	12/01/08	23,050,000	1,460,928	3
						4
12/01/87	12/01/05	12/01/87	12/01/05	9,000,000	652,500	5
						6
07/01/89	04/01/07	07/01/89	04/01/07	60,000,000	4,080,000	7
						8
						9
03/01/92	03/01/19	03/01/92	03/01/19	27,900,000	991,058	10
						11
09/01/93	09/01/19	09/01/93	09/01/19	50,000,000	1,784,539	12
						13
09/01/93	09/01/19	09/01/93	09/01/19	50,000,000	1,741,200	14
						15
						16
				270,624,674	13,262,730	17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
[redacted]				$1,354,124,674	$83,866,132	33

< Page 256.2 Line 17 Column a >

Detail for Account 224 of Net Changes During the Year
(Dollars in Thousands)

	Balance 12-31-95	Additions	Reductions	Balance 12-31-96
Public Improvements	$979		$931	$48
Genstar	21		1	20
Mankato Service Center	174		24	150
ESOP Loans	9,874	15,000	7,302	17,572
Guar Agmt-Poll Control				
Red Wing	24,250		500	23,750
Monticello 1975	3,500			3,500
Monticello 1973	5,700		200	5,500
Ind Dev Rev Bonds				
Sioux Falls	195		60	135
Non-Collater. Poll Control				
Becker 1987	9,000			,000
Anoka Cty Series 1985	24,150		1,100	23,050
Becker Poll Control 1989A	60,000			60,000
Becker Poll Control 1992A	27,900			27,900
Becker Poll Control 1993A	50,000			50,000
Becker Poll Control 1993B	50,000			50,000
TOTAL	$265,743	$15,000	$10,118	$270,625

< Page 257.1 Line 18 Column e >

Various

< Page 257.1 Line 20 Column e >

Various

< Page 257.1 Line 25 Column e >

Various

< Page 257.1 Line 29 Column e >

Various

< Page 257.1 Line 32 Column e >

Various

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

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 members, 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)	$274,539,042
2	Reconciling Items for the Year	[redacted]
3		
4	Taxable Income Not Reported on Books	
5		* 83,908,793
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	[redacted]
10		* 409,133,842
11		
12		
13		
14	Income Recorded on Books Not Included in Return	[redacted]
15		* (2,881,652)
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	[redacted]
20		* (458,739,649)
21		
22		
23		
24		
25	Equity in Earnings of Subsidiary Companies	* (56,706,362)
26	Total Income Tax Expense	137,675,095
27	Federal Tax Net Income	386,929,109
28	Show Computation of Tax:	
29	35.00% of Federal Tax Net Income	135,425,188
30		
31	Plus:	
32	Other	1,248,855
33		
34		
35	Total Current Federal Income Tax Payable	136,674,043
36		
37		
38		
39		
40		
41		
42		
43		
44		

< Page 261 Line 5 Column b >

TAXABLE INCOME NOT REPORTED ON BOOKS:

Book Income-Wisconsin/South Dakota AFDC	147,000
CIAC-Connection Fees	4,836,561
Earnings on Non-Qualified Decommissioning Fund	1,992,270
Income Earned on Annuity Payments	32,786
Sale of Emission Allowances	62,382
Tax Benefit Transfer Gain on Disposals	188,931
Tax Benefit Transfer Rental Income	70,579,792
Unbilled Revenues	6,069,071
TOTAL	83,908,793

< Page 261 Line 10 Column b >

DEDUCTION RECORDED ON BOOKS NOT DEDUCTED FOR RETURN:

Accrued Vacation Paid	671,311
Ad Valorem Tax-Coal	175,615
AFDC-Equity	140,447
Bad Debt Reserve	4,779,987
Board of Directors Retirement Benefit	10,506
Book Depreciation	244,427,243
Book Insurance Expense	46,283
Book Nuclear Fuel Expense	57,050,322
Book Rent Expense-Capitalization for Tax	5,802,306
Book Unamortized Cost of Retired Debt Over Amort.	3,319,524
Compensation Expense-Stock Option Plan	90,614
Decontamination and Decommissioning Assessment	2,868,069
Deferred Compensation Plan Accruals	1,144,667
Deferred Gas Costs	3,148,204
Interest Capitalized Under IRC Sect 263A	3,792,214
Interest Income/Expense on Disputed Tax	2,199,080
Low Income Discount Program	4,004,795
Meals and Entertainment Disallowance	1,502,753
Medical Deductions-Self Insured	62,674
Nondeductible EPIC/Lobbying Expense	1,000,000
Prepaid Maintenance Contracts	1,242
Post Retirement Benefits-FAS 106	17,145,556
PUCIP Deduction, Net of Book Amortization-Electric	5,733,964
PUCIP Deduction, Net of Book Amortization-Gas	447,466
RDF Miscellaneous Expenditures	133,253
Regulatory Liability-Settlement	8,229,167
Saver Switch	5,541,508
Settlement Payments-Nonreimbursed	1,219,348
Total Nuclear Decommissioning	34,445,724
TOTAL	409,133,842

< Page 261 Line 15 Column b >

INCOME RECORDED ON BOOKS NOT INCLUDED IN RETURN

Book Tax Benefit Transfer Income	(460,294)
CIAC-Customer Advances	(129,921)
Increase in Cash Surrender Value-Life Insurance	(2,291,437)
TOTAL	(2,881,652)

< Page 261 Line 20 Column b >

DEDUCTIONS ON RETURN NOT CHARGED AGAINST BOOK INCOME:

AFDC Debt	(6,712,394)
Coal Mine Reclamation Reserve	(2,383,499)
Environmental Cleanup	(917,409)
Environmental Tax	(508,400)
Environmental Remediation	(57,696)
ESOP Dividends & Plan Contributions	(7,827,086)
Executive Long Term Incentive Plan	(957,157)
External Qualified Nuclear Decommissioning Funding	(15,728,328)
Fees on Non-Qualified Ext. Decommissioning Funding	(275,827)
Interest Expense on Vehicle Leases	(1,572,876)
Interest Expense-Capital Leases	(4,260,629)
Internally Developed Software	(5,427,886)
Loss From Partnership Investment	(500,000)
Low Level Radiation Waste	(9,063)
Nuclear Fuel Removal Fee-1 ML/KWH	(11,276,720)
Pending Lawsuits	(2,141,000)
Post Employment Benefits-FAS 112	(205,966)
P.I. Independent Spent Fuel Isolation Devices	(8,848,096)
Prepaid Insurance	(6,199,277)
Rate Refunds	(1,164)
Reengineering Analysis	(6,685,581)
Environmental & Regulatory Reserves	(2,735,394)
Sec 481(a) Adjustment for Interest Cap Under 263A	(647,302)
Severance Accrual	(1,948,031)
State Income Taxes	(36,182,643)
Stock Loss on External Decommissioning Fund	(1,124,551)
Tax Amortization	(5,291,675)
Tax Benefit Transfer Amortization Expense	(63,192)
Tax Benefit Transfer Interest Expense	(30,242,619)
Tax Depreciation	(270,535,969)
Tax Loss on Sale of Fixed Assets	(3,977,355)
Tax Removal Cost Over Book Accrual	(6,692,099)
Tax Repair Allowance	(13,143,769)
Litigation Costs	(3,587,221)
Workers Compensation	(71,775)
TOTAL	(458,739,649)

< Page 261 Line 25 Column b >

Northern States Power Company (Minnesota) is a member of an affiliated group which will file a consolidated Federal Income Tax Return for the year 1996. The other members of the affiliated group and the Federal Income tax provision of each are:

Northern States Power Company (Wisconsin)	19,591,836
Cenerprise Inc.	(4,044,752)
Cormorant Corporation	(996)
Eloigne Corporation	(1,487,611)
Energy Masters Corp.	558,384
First Midwest Auto Park, Inc.	182,617
NRG Energy, Inc.	632,897
Seren Innovations, Inc.	0
United Power and Land Company	294,974
Viking Gas Transmission Company	1,114,206

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 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.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.

2. Include on this page, taxes paid during the year and charged direct to final accounts,(not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.

3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued,(b)amounts credited to proportions of prepaid taxes chargeable to current year, and(c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.

4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See Instruction 5) (a)		BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)		Adjustments (f)
1	FEDERAL TAXES							
2								
3	Income Tax	1996	10,284,605		136,114,329	117,450,000	*	2,590,809
4		1995				17,800,000		
5								
6	FICA	1996	1,540,289		26,352,327	25,157,089		
7		1995						
8								
9	Fed Unemployment	1996	5,649		380,973	381,845		
10		1995						
11								
12	SUBTOTAL		11,830,543	0	162,847,629	160,788,934		2,590,809
13								
14	STATE TAXES-MINNESOTA							
15								
16	Income Tax	1996	2,758,422		35,657,860	26,074,000	*	(2,130,538)
17		1995				3,600,000		
18								
19	Unemployment	1996	(156,088)		1,969,818	1,990,505		
20		1995						
21								
22	Motor Vehicle	1996	17,807		(3,392)	13,993		
23		1995						
24								
25	LOCAL TAXES-MINNESOTA							
26								
27	Real Estate	1996	100,275,777		92,180,362			
28		1995				98,224,699		
29								
30	Personal Property	1996	69,628,454		68,540,059			
31		1995				68,469,920		
32								
33								
34								
35								
36								
37								
38								
39								
40								
41	TOTAL							

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes) covers more than 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 footnote. 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 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also show 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					
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)	Adjustment to Ret. Earnings (Account 439) (k)		Other (l)	Line No.
							1
							2
13,739,743		122,977,527			*	13,136,802	3
							4
							5
2,735,527		16,549,457			*	9,802,870	6
							7
							8
4,777		240,149			*	140,824	9
							10
							11
16,480,047	0	139,767,133	0	0		23,080,496	12
							13
							14
							15
6,611,744		31,141,340			*	4,516,520	16
							17
							18
(176,775)		1,256,766			*	713,052	19
							20
							21
422		0			*	(3,392)	22
							23
							24
							25
							26
94,231,440		89,164,992			*	3,015,370	27
							28
							29
69,698,[illegible]93		54,872,268			*	13,667,791	30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.

2. Include on this page, taxes paid during the year and charged direct to final accounts,(not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.

3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued,(b)amounts credited to proportions of prepaid taxes chargeable to current year, and(c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.

4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See Instruction 5) (a)		BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
1	GROSS EARNINGS-MINNESOTA						
2							
3	Minneapolis	1996	904,293		11,719,728	10,790,394	
4		1995				904,293	
5							
6	St Paul	1996	1,012,365		14,723,840	13,680,652	
7		1995				1,012,365	
8							
9	So St Paul	1996	112,323		458,778	342,446	
10		1995				112,323	
11							
12	White Bear Lake	1996	154,977		154,349	0	
13		1995				154,977	
14							
15	Winona	1996	128,941		672,941	470,350	
16		1995				128,941	
17							
18	Lake City	1996	32,940		39,523	0	
19		1995				32,925	
20							
21	West St Paul	1996	266,932		477,108	266,932	
22		1995				219,456	
23							
24	Coon Rapids	1996	28,154		367,616	337,760	
25		1995				28,154	
26							
27	FRANCHISE-MINNESOTA						
28	East Grand Forks	1996	90,758		126,908	0	
29		1995				90,758	
30							
31	Moorhead	1996	36,422		290,478	241,902	
32		1995				36,422	
33							
34	Moundsview	1996	27,843		245,437	217,586	
35		1995				27,843	
36							
37	St Cloud	1996	103,231		1,381,157	1,223,397	
38		1995				103,231	
39							
40	SUBTOTAL		175,423,551	0	229,002,570	228,796,224	(2,130,538)
41	TOTAL						

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes) covers more than 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 footnote. 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 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also show 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				
(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)	Adjustment to Ret. Earnings (Account 439) (k)	Other (l)	Line No.
						1
						2
929,334		11,735,695			* (15,967)	3
						4
						5
1,043,188		10,829,864			* 3,893,976	6
						7
						8
116,332		188,348			* 270,430	9
						10
						11
154,349		178,625			* (24,276)	12
						13
						14
202,591		673,409			* (468)	15
						16
						17
39,538		17			* 39,506	18
						19
						20
257,652		373,481			* 103,627	21
						22
						23
29,856		367,802			* (186)	24
						25
						26
						27
126,908		0			* 126,908	28
						29
						30
48,576		0			* 290,478	31
						32
						33
27,851		123,597			* 121,840	34
						35
						36
157,760		988,248			* 392,909	37
						38
						39
173,499,359	0	201,894,452	0	0	27,108,118	40
						41

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.

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4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See Instruction 5) (a)		BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
1	STATE TAXES-NORTH DAKOTA						
2							
3	Income Taxes	1996	643,418		524,783	759,000	* 907,846
4		1995				46,000	
5							
6	Unemployment	1996	(567)		2,802	2,800	
7		1995					
8							
9	Motor Vehicle	1996	(56)		7,571	7,571	
10		1995					
11							
12	Personal Property	1996	2,333,555		2,368,457		
13		1995				2,335,148	
14							
15	LOCAL TAXES-NORTH DAKOTA						
16							
17	Real Estate	1996	(2,015)		7,135		
18		1995				4,342	
19							
20	FRANCHISE-NORTH DAKOTA						
21							
22	Fargo	1996	137,538		1,335,702	1,176,037	
23		1995				137,538	
24							
25	Grand Forks	1996	182,382		719,121	542,833	
26		1995				182,382	
27							
28	Larimore	1996	3,317		14,107	10,881	
29		1995				3,317	
30							
31	Hatton	1996	2,173		8,582	6,432	
32		1995				2,173	
33							
34	SUBTOTAL		3,299,745	0	4,988,260	5,216,454	907,846
35							
36							
37							
38							
39							
40							
41	TOTAL						

Name of Respondent Northern States Power Company (Minnesota)	This Report is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes) covers more than 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 footnote. 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.

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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				
(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)	Adjustment to Ret. Earnings (Account 439) (k)	Other (l)	Line No.
						1
						2
1,271,047		1,389,932			* (865,149)	3
						4
						5
(565)		1,224			* 1,578	6
						7
						8
(56)		0			* 7,571	9
						10
						11
2,366,864		1,726,556			* 641,901	12
						13
						14
						15
						16
778		7,135			0	17
						18
						19
						20
						21
159,665		914,189			* 421,513	22
						23
						24
176,288		504,261			* 214,860	25
						26
						27
3,226		15,737			* (1,630)	28
						29
						30
2,150		0			* 8,582	31
						32
						33
3,979,397	0	4,559,034	0	0	429,226	34
						35
						36
						37
						38
						39
						40
						41

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.

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4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See Instruction 5) (a)		BALANCE AT BEGINNING OF YEAR: Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR: Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
1	STATE TAXES-SOUTH DAKOTA						
2							
3	Motor Vehicle	1996	(283)		564	564	
4		1995					
5							
6	Personal Property	1996	2,041,355		2,560,793		
7		1995				2,033,885	
8							
9	Unemployment	1996	(2,628)		6,192	6,132	
10		1995					
11							
12	LOCAL TAXES-SOUTH DAKOTA						
13							
14	Real Estate	1996	112,949		35,215		
15		1995				74,250	
16							
17	SUBTOTAL		2,151,393	0	2,602,764	2,114,831	0
18							
19	STATE TAXES-WISCONSIN						
20							
21	Income Tax	1996	0	0		594,000	(102,410)
22		1995				105,615	
23							
24	Unemployment	1996	3,148		343		
25		1995					
26							
27	SUBTOTAL		3,148	0	343	699,615	(102,410)
28							
29							
30							
31							
32							
33							
34	* Other Sales Tax						
35							
36							
37							
38							
39							
40							
41	TOTAL		$192,708,380	0	$399,441,566	$397,616,058	$1,265,707

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column(a).

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BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				
(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)	Adjustment to Ret. Earnings (Account 439) (k)	Other (l)	Line No.
						1
						2
(283)		0			* 564	3
						4
						5
2,568,263		2,536,966			23,827	6
						7
						8
(2,568)		3,210			* 2,982	9
						10
						11
						12
						13
73,914		35,215			0	14
						15
						16
2,639,326	0	2,575,391	0	0	27,373	17
						18
						19
						20
(802,025)		0			0	21
						22
						23
3,491		0			343	24
						25
						26
(798,534)	0	0	0	0	343	27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
$195,799,595	0	$348,796,010	0	0	$50,645,556	41

< Page 262 Line 3 Column f >

Intercompany Transactions, Tax Refunds, Transfer of Refuse-derived fuel operations to subsidiary, Transfer of Long-term Taxes Receivable.

< Page 262 Line 16 Column f >

Intercompany Transactions and Transfer of Long-term Taxes Receivable.

< Page 262.2 Line 3 Column f >

Transfer of Long-term Taxes Receivable

< Page 262.3 Line 34 Column a >

Total does not include state and local use taxes of $364,391 in column (b) and $568,279 in column (g).

< Page 263 Line 3 Column l >

Includes $11,982,750-Gas Utility; $694,931-Acct. No. 409.2; $459,121-Other.

< Page 263 Line 6 Column l >

Includes $1,840,020-Gas Utility; $2,698,478-Acct. No. 107 & 108; $5,264,372-Other.

< Page 263 Line 9 Column l >

Includes $26,788-Gas Utility; $39,812-Acct. No. 107 & 108; $74,224-Other.

< Page 263 Line 16 Column l >

Includes $3,034,366-Gas Utility; $1,482,154-Acct. No. 409.2.

< Page 263 Line 19 Column l >

Includes $132,525-Gas Utility; $207,225-Acct. No. 107 & 108; $373,302-Other.

< Page 263 Line 22 Column l >

Acct. No. 184.

< Page 263 Line 27 Column l >

Includes $1.620,545-Gas Utility; $449,409-Acct. No. 107; $1,155,929-Acct. No. 408.2; ($210,513)-Other.

< Page 263 Line 30 Column l >

Includes $13,585,704-Gas Utility; $77,707-Acct. No. 107; $4,380-Other.

< Page 263.1 Line 3 Column l >

Other

< Page 263.1 Line 6 Column l >

Includes $4,092,261-Gas Utility; ($198,285)-Other.

< Page 263.1 Line 9 Column l >

Includes $126,804-Gas Utility; $143,626-Other.

< Page 263.1 Line 12 Column l >

$30,576-Gas Utility; ($54,852)-Other

< Page 263.1 Line 15 Column l >

$15,772-Gas Utility; ($16,240)-Other

< Page 263.1 Line 18 Column 1 >

Includes $23,140-Gas Utility; $16,366-Other.

< Page 263.1 Line 21 Column 1 >

Other

< Page 263.1 Line 24 Column 1 >

Other

< Page 263.1 Line 28 Column 1 >

Includes $70,041-Gas Utility; $56,867-Other.

< Page 263.1 Line 31 Column 1 >

Includes $161,875-Gas Utility; $128,603-Other.

< Page 263.1 Line 34 Column 1 >

Includes $67,515-Gas Utility; $54,325-Other.

< Page 263.1 Line 37 Column 1 >

Includes $396,180-Gas Utility; ($3,271)-Other.

< Page 263.2 Line 3 Column 1 >

Includes $135,433-Gas Utility; $18,254-
Acct. No. 409.2; ($1,018,836)-Other.

< Page 263.2 Line 6 Column 1 >

Includes $686-Gas Utility; $232-
Acct. No. 107 & 108; $660-Other.

< Page 263.2 Line 9 Column 1 >

Acct. No. 184

< Page 263.2 Line 12 Column 1 >

Gas Utility

< Page 263.2 Line 22 Column 1 >

Includes $547,445-Gas Utility;
$(125,932)-Other.

< Page 263.2 Line 25 Column 1 >

Includes $277,150-Gas Utility;
($62,290)-Other.

< Page 263.2 Line 28 Column 1 >

Other

< Page 263.2 Line 31 Column 1 >

Other

< Page 263.3 Line 3 Column 1 >

Acct. No. 184

< Page 263.3 Line 9 Column 1 >

Includes ($7)-Gas Utility; $898-
Acct. No. 107 & 108; $2,091-Other.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	8,405,669				349,671	(8,369)
4	7%						
5	10%	112,210,739				7,216,175	(69,939)
6							
7							
8	TOTAL	$120,616,408				$7,565,846	($78,308)
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	Gas Utility						
12	4%	320,278				29,216	723
13	10%	8,032,216				373,315	1,896
14							
15	Common Utility						
16	4%	27,774				1,259	(4)
17	10%	642,012				81,220	(6,886)
18							
19							
20	NON-OPERATING						
21							
22	Non Utility						
23	10%	7,857,092					(2,322,089)
24							
25	Non Utility-RDF						
26	10%	743,774				54,757	
27							
28							
29	(a) Common Alloc						
30	Electric	545,732				57,100	(4,770)
31	Gas	124,053				25,379	(2,120)
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)
[redacted]	[redacted]
0	
8,047,629	
104,924,625	
$112,972,254	
[redacted]	
291,785	
7,660,797	
26,511	
553,906	
5,535,003	
689,017	
483,862	
96,554	
	* Ajustment Expl

Adjustment Explanation

< Page 266 Column g >

1) Adjustments consist of:

- True-ups of deferred tax credits recorded to reflect differences between tax returns filed and prior year accounting accruals:	
Affecting income	(82,579)
Not affecting income	0
- Amortization of non-utility tax benefits transfer (safe harbor) lease credits which have no income effect	(2,322,089)
- Transfer of non-utility assets and associated tax credits to wholely owned subsidiary	0
- Miscellaneous income adjustments	0
TOTAL	(2,404,668)

2) Credits are flowed-through (amortized) to income ratably over the estimated life of the property.

3) Reconciliation page 114, line 18:

- Allocations to Current Year's income (column (f) on page 266	(8,105,613)
- Less non-utility portion	54,757
- Return to accrual adjustments per (1) above	(82,579)
- Miscellaneous income adjustments per (1) above	0
Utility Investment Tax Credit Adjustment	(8,133,435)

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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 $10,000, whichever is greater) may be grouped by classes.

Line No.	Description of Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	LONG-TERM OBLIGATIONS FOR					
2	QUALIFIED EMPLOYEE BENEFIT PLANS:					
3						
4	Unfunded Early Retirement Costs	16,792,690	186	16,792,690	0	0
5	(1988 Program)					
6						
7						
8	LONG-TERM OBLIGATIONS FOR DEFERRED					
9	COMPENSATION PROGRAMS:					
10						
11	Unfunded Nonqualified Pension	4,266,918	232	836,434	1,260,000	4,690,484
12	Benefit Costs					
13						
14	Deferred Compensation - Salary	15,778,356	*	1,754,985	2,332,394	16,355,765
15	Deferrals					
16						
17	Deferred Compensation - Accrued	5,197,728	*	2,769,913	2,951,850	5,379,665
18	Earnings					
19						
20	Deferred Compensation - Accrued	2,710,500	232	30,894	41,400	2,721,006
21	Directors Retirement Benefits					
22						
23						
24	LONG-TERM ACCRUALS FOR OTHER					
25	EXPENSE ITEMS:					
26						
27	Injury Compensation - FASB 112	9,130,024		0	2,262,957	11,392,981
28						
29	Environmental & Regulatory	13,477,073	*	5,482,790	2,847,396	10,841,679
30	Reserves					
31						
32	Hazardous Waste Disposal	25,273	421	9,063	0	16,210
33						
34	Nuclear Insurance - NEIL	0	924	3,686,585	3,686,585	0
35						
36						
37	LONG-TERM DEPOSITS, ADVANCE					
38	BILLINGS & RECEIPTS:					
39						
40	Intercompany billings -	2,264,867	186	3,474,346	1,209,479	0
41	Subsidiary Pension Funding					
42						
43	Koch Refinery Maintenance Reserve	542,843	*	135,720	0	407,123
44	(amortized over period 1993-1999)					
45						
46	Deposit - MN Methane	41,305		0	1,621	42,926
47	TOTAL					

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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 $10,000, whichever is greater) may be grouped by classes.

Line No.	Description of Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Deposit - Landfill Power	$126,884		0	$103,174	$230,058
2						
3	Other	5,400	232	2,200	800	4,000
4						
5						
6	DEFERRED INCOME ITEMS:					
7						
8	IPP Power Contract Billing	2,480,410	186	15,953	139,494	2,603,951
9	Adjustments					
10						
11	Other	500	172	531	2,000	1,969
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	$72,840,771	[redacted]	$34,992,104	$16,839,150	$54,687,817

< Page 269 Line 14 Column c >

Accounts charged include:	184	$1,375
	232	144,916
	253	1,380,822
	421	227,872
	TOTAL	$1,754,985

< Page 269 Line 17 Column c >

Accounts charged include:	232	$2,596,977
	253	11,204
	421	161,732
	TOTAL	$2,769,913

< Page 269 Line 29 Column c >

Accounts charged include:	182.4	$2,376,666
	184	128
	232	48,211
	242	1,044,100
	426.5	2,013,685
	TOTAL	$5,482,790

< Page 269 Line 43 Column c >

Accounts charged include:	184.1	$108,576
	562	27,144
	TOTAL	$135,720

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Name of Respondent	This Report Is:	Date of Report	Year of Report
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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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	3,491,182	0	435,166
5	Other			
6				
7				
8	TOTAL Electric(Enter Total of lines 3 thru 7)	$3,491,182	0	$435,166
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16	Other (Specify)			
17	TOTAL (Acct 281) (Total of 8,15,and 16)	$3,491,182	0	$435,166
18	Classification of TOTAL			
19	Federal Income Tax	3,491,182		435,166
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

income and deductions.

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
[redacted]							1
							2
							3
0	0					3,056,016	4
							5
							6
							7
0	0					$3,056,016	8
[redacted]							9
							10
							11
							12
							13
							14
							15
							16
0	0					$3,056,016	17
[redacted]							18
						3,056,016	19
							20
							21

NOTES(Continued)

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	$791,068,527	$48,640,395	$41,387,286
3	Gas	54,006,917	3,964,842	1,947,073
4	Other (Define)	0	0	0
5	TOTAL (Enter Total of lines 2 thru 4)	$845,075,444	$52,605,237	$43,334,359
6	Other (Specify)	6,382,766	0	0
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	$851,458,210	$52,605,237	$43,334,359
10	Classification of TOTAL			
11	Federal Income Tax	685,820,655	41,654,411	35,494,087
12	State Income Tax	165,637,555	10,950,826	7,840,272
13	Local Income Tax			

NOTES

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

income and deductions.

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
[redacted]							1
0	0		$12,333,933		$4,108,007	$790,095,710	2
0	0		3,094,458		(3,009)	52,927,219	3
0	0		0		0	0	4
0	0		$15,428,391		$4,104,998	$843,022,929	5
66,822	0		0		0	6,449,588	6
							7
							8
$66,822	0		$15,428,391		$4,104,998	$849,472,517	9
[redacted]							10
47,850	0		13,787,885		3,234,912	681,475,856	11
18,972	0		1,640,506		870,086	167,996,661	12
							13

NOTES(Continued)

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric	[redacted]		
3	Electric	$170,586,851	$9,529,398	$19,840,885
4				
5				
6				
7				
8	Other	0	0	0
9	TOTAL Electric (Total of lines 3 thru 8)	$170,586,851	$9,529,398	$19,840,885
10	Gas	[redacted]		
11	Gas	11,994,248	686,428	3,068,761
12				
13				
14				
15				
16	Other	0	0	0
17	TOTAL Gas (Total of lines 11 thru 16)	$11,994,248	$686,428	$3,068,761
18	Other (Specify) Non Operating	0	0	0
19	TOTAL (Acct 283) (Enter Total of lines 9,17 and 18)	$182,581,099	$10,215,826	$22,909,646
20	Classification of TOTAL	[redacted]		
21	Federal Income Tax	144,554,039	8,003,797	18,117,297
22	State Income Tax	38,027,060	2,212,029	4,792,349
23	Local Income Tax	0	0	0

NOTES

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283)(Continued)

income and deductions.

3. Provide in the space below explanations for page 276 and 277. Include amounts relating to insignificant items listed under Other.

4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credits to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
[redacted]							1
							2
0	0		$2,645,479		$10,080,512	$167,710,397	3
							4
							5
							6
							7
0	0		0		0	0	8
0	0		$2,645,479		$10,080,512	$167,710,397	9
[redacted]							10
0	0		356,657		647,241	9,902,499	11
							12
							13
							14
							15
0	0		0		0	0	16
0	0		$356,657		$647,241	$9,902,499	17
203,751			0		0	203,751	18
$203,751	0		$3,002,136		$10,727,753	$177,816,647	19
[redacted]							20
159,547	0		2,340,377		8,410,504	140,670,213	21
44,204	0		661,759		2,317,249	37,146,434	22
0	0		0		0	0	23

NOTES (Continued)

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

OTHER REGULATORY LIABILITIES (Account 254)

1. Reporting below the particulars (details) called for concerning other regulatory liabilities which are created through the ratemaking actions of regulatory agencies (and not includable in other amounts).
2. For regulatory liabilities being amortized, show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	DEBITS Account Credited (b)	DEBITS Amount (c)	Credits (d)	Balance at End of Year (e)
1	EMPLOYEE BENEFIT COSTS:				
2					
3	Pension Costs Collected in Rates in Excess of				
4	FASB 87 Levels		0	23,572,000	45,080,000
5					
6	INCOME TAX ITEMS:				
7					
8	ITC Gross-Up to Pretax Rate Levels - FASB 109	190	11,346,000	5,436,000	84,224,000
9					
10	Deferred Taxes Collected in Rates in Excess of				
11	Current Tax Accrual Levels - FASB 109	190	15,307,000	45,293,000	88,934,000
12		282	22,514,000		
13					
14	Deferrals of IRS & State Interest/Other Credits		0	0	366,665
15					
16	OTHER INCOME ITEMS DEFERRED DUE TO EXPECTED RATE				
17	FLOWBACK:				
18					
19	Fuel Refunds	431	106	3,258,029	3,310,479
20					
21	Unrealized Gains on Decommissioning Trust				
22	Investments - FASB 115	128	10,653,498	27,287,570	43,008,351
23					
24	Gains from Sales of Emission Allowances	143	4,954	80,931	329,067
25		146	11,667		
26		232	1,926		
27					
28	Gas Site Remediation Reimbursement	407.4	92,931	0	0
29					
30	Rates Collected in Excess of Low Income	184	55,801	4,062,926	7,950,079
31	Discounts Provided to Customers	232	142		
32		431	2,189		
33					
34	Settlements (amortized over 4 years beginning			10,000,000	10,000,000
35	in 1997)				
36					
37					
38					
39					
40					
41	TOTAL		$59,990,214	$118,990,456	$283,202,641

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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.

2. 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.

3. If increases or decreases from previous year (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)	OPERATING REVENUES Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	$608,587,348	$614,669,737
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr.4)	322,296,654	307,694,346
5	Large (or Ind.) (See Instr.4)	* 741,630,206	737,215,692
6	(444) Public Street and Highway Lighting	16,754,211	16,471,516
7	(445) Other Sales to Public Authorities	8,096,226	8,159,922
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	812,806	209,563
10	TOTAL Sales to Ultimate Consumers	$1,698,177,451	$1,684,420,776
11	(447) Sales for Resale	$81,569,528	$116,058,033
12	TOTAL Sales of Electricity	$1,779,746,979	$1,800,478,809
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	$1,779,746,979	$1,800,478,809
15	Other Operating Revenues		
16	(450) Forfeited Discounts	$6,625,162	$4,739,443
17	(451) Miscellaneous Service Revenues	2,883,765	4,077,593
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	1,836,868	1,967,729
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	* 214,939,372	207,847,436
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	$226,285,167	$218,632,201
27	TOTAL Electric Operating Revenues	$2,006,032,146	$2,019,111,010

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

ELECTRIC OPERATING REVENUES (Account 400)(Continued)

4. 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.)

5. See pages 108-109, Important Changes During Year, for important new territory added and important rate increases or decreases.

6. For lines 2,4,5,and 6, see page 304 for amounts relating to unbilled revenue by accounts.

7. Include unmetered sales. Provide details of such sales in a footnote.

MEGAWATT HOURS SOLD		AVG. NO. CUSTOMERS PER MONTH		
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	Line No.
				1
8,140,292	8,236,883	1,055,762	1,065,823	2
				3
5,194,550	4,880,244	130,848	134,353	4
16,093,730	16,049,829	7,554	7,078	5
* 140,644	139,867	3,214	1,894	6
135,009	136,180	2,517	2,540	7
				8
17,325	11,926			9
29,721,550	29,454,929	1,199,895	1,211,688	10
4,472,026	6,043,584	52	58	11
34,193,576	35,498,513	1,199,947	1,211,746	12
				13
34,193,576	35,498,513	1,199,947	1,211,746	14

Line 12, Column (b) includes $ 8,150,276 of unbilled revenues.

Line 12, Column (d) includes 156,529 MWH relating to unbilled revenues.

< Page 300 Line 5 Column b >

Commercial and industrial sales are classified as "Large" for purposes of this report if customer has a minimum registered demand of 100 KW or more.

< Page 300 Line 21 Column b >

Includes reimbursement from Northern States Power Company (Wisconsin), for production and transmission costs shared under an interchange agreement between the companies dated Sept. 17, 1984.

Fixed Production Expense	$103,422,943
Variable Production Expense	$69,972,565
Transmission Expense	$13,685,491

< Page 301 Line 6 Column d >

MWH sold for automatic protective lighting and street lighting purposes (unmetered) is estimated from connected load and hours of burning.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 customers, average KWh per customer, and average revenue per KWh, excluding data 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," pages 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	519	$26,426	*	87	5,965	5.4770¢
2	A01,D01,E01 Res	5,433,824	414,339,805		764,926	7,103	7.6251¢
3	A02,D02,E02 Res TOD	694	45,592		32	20,411	6.5697¢
4	A03,D03,E03 Res Underground	1,656,441	128,948,180		229,316	7,223	7.7846¢
5	A04,D04,E04 Res TOD Under	224	16,111		26	8,615	7.1924¢
6	E06 Res Heat Pump	34	1,883	*	8	4,250	5.5382¢
7	A05,D05,E10 Energy-Control	288,145	20,504,981	*	3	96,048,333	7.1162¢
8	A06,D10,E11 Ltd Off-Peak	2,582	82,389	*	210	12,295	3.1908¢
9	A07,D11,E12 Auto Prot Ltg	9,456	1,163,543	*	13,156	718	12.3048¢
10	UNBILLED	(15,074)	(927,074)				6.1501¢
11	TOTAL Res W/O Space Heating	7,376,845	564,203,838		1,007,766	7,319	7.6483¢
12							
13	A01,D01,E01 Res	592,281	34,045,518		37,596	15,753	5.7482¢
14	A02,D02,E02 Res TOD	1,060	55,112		27	39,259	5.1992¢
15	A03,D03,E03 Res Underground	126,449	7,975,267		9,378	13,483	6.3071¢
16	A04,D04,E04 Res TOD Under	253	15,827		12	21,083	6.2557¢
17	A05,D05,E10 Energy-Control	35,168	1,517,256	*	983	35,776	4.3143¢
18	A06,D10,E11 Ltd Off-Peak	7	199				2.8428¢
19	UNBILLED	8,229	774,331				9.4097¢
20	TOTAL Res W Space Heating	763,447	44,383,510		47,996	15,906	5.8135¢
21							
22	A05,D05,E10 Energy-Control	692	26,531	*	58	11,931	3.8339¢
23	A06,D10,E11 Ltd Off-Peak	1,915	79,993	*	78	24,551	4.1771¢
24	A07,D11,E12 Auto Prot Ltg	43,603	4,283,966	*	15,052	2,896	9.8249¢
25	A09 Small Gen Svc	20	9,217		144	138	46.0850¢
26	A10,D12,E13 Small Gen Svc	956,995	71,779,115		76,160	12,565	7.5004¢
27	A11,D13,E05 Water Heating	2,353	147,682	*	245	9,604	6.2763¢
28	A12,D14,E14 Sm Gen TOD	38,844	2,483,956		3,178	12,222	6.3946¢
29	A13,D15 Direct Current	14	17,731		17	823	126.6500¢
30	A14,D16,E15 General Service	3,427,273	209,420,628		31,022	110,478	6.1104¢
31	A15,D17,E16 Gen Svc TOD	581,959	25,170,883		1,344	433,005	4.3251¢
32	A18,D18 Gen Svc TOD	10,278	834,029		3,172	3,240	8.1147¢
33	A20,D20,E20 Peak Control	33,445	2,101,213		268	124,794	6.2825¢
34	A21,D21,E21 Pk Control TOD	1,766	100,390		12	147,166	5.6845¢
35	A23 Pk Cntl Tiered	31,430	1,625,876		93	337,956	5.1730¢
36	A24 Pk Cntl Tier TOD	26,412	1,220,131		3	8,804,000	4.6196¢
37	A26,D22,E22 Energy Control	3,261	105,583		2	1,630,500	3.2377¢
38	UNBILLED	34,290	2,889,730				8.4273¢
39	TOTAL Small Comm & Industrial	5,194,550	322,296,654		130,848	39,699	6.2045¢
40							
41	Total Billed						
42	Total Unbilled Rev.(See Instr. 6)						
43	TOTAL						

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 customers, average KWh per customer, and average revenue per KWh, excluding data 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," pages 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	A06,D10,E11 Ltd Off-Peak	914	$25,343	* 8	114,250	2.7727¢
2	A14,D16,E15 General Service	5,560,690	296,975,557	4,398	1,264,080	5.3406¢
3	A15,D17,E16 Gen Svc TOD	5,334,975	223,648,624	941	5,669,473	4.1921¢
4	A16 Gen 3-Part TOD	78,747	3,388,541	8	9,843,375	4.3030¢
5	A17 Ford Motor	8,000	371,898	1	8,000,000	4.6487¢
6	A20,D20,E20 Peak Control	1,064,282	51,855,952	809	1,315,552	4.8723¢
7	A21,D21,E21 Pk Control TOD	730,537	30,908,151	82	8,908,987	4.2308¢
8	A22 Pk Cntl 3-Pt TOD	25,829	951,467	25	1,033,160	3.6837¢
9	A23 Pk Cntl Tiered	1,003,851	49,108,522	1,051	955,138	4.8920¢
10	A24 Pk Ctr Tier TOD	1,151,883	47,292,653	155	7,431,503	4.1056¢
11	A25 Pk Cntl Tier 3-Pt TOD	385,227	11,864,170	6	64,204,500	3.0797¢
12	A26,D22,E22 Energy Control	281,257	9,296,120	54	5,208,462	3.3052¢
13	A27 Tier 1 Energy Control	322,989	9,627,474	15	21,532,600	2.9807¢
14	UNBILLED	144,549	6,315,734			4.3692¢
15	TOTAL Large Comm & Industrial	16,093,730	741,630,206	7,554	2,130,491	4.6081¢
16						
17	A30,D30,E30 St Ltg Comp-Owned	53,556	12,287,577	942	56,853	22.9434¢
18	A31 Street Lighting	44	7,275	32	1,375	16.5340¢
19	A32,D31,E31 St Ltg Cust-Owned	74,473	3,669,160	1,493	49,881	4.9268¢
20	A34,D33,E32 St-Ltg Metered Cust	6,062	306,166	481	12,602	5.0505¢
21	A35,D32,E33 Ornmntl StLtg Cust	4,407	221,321	165	26,709	5.0220¢
22	A37 St Ltg-Saint Paul	1,504	186,599	86	17,488	12.4068¢
23	A38 Telephone Booth	1	1,243	15	66	124.3000¢
24	UNBILLED	597	74,870			12.5410¢
25	TOTAL Street & Hwy Lighting	140,644	16,754,211	3,214	43,759	11.9124¢
26						
27	A40,D40 Small Muni Pump	6,601	496,692	1,250	5,280	7.5244¢
28	A41,D41 Muni Pump	127,838	7,531,132	752	169,997	5.8911¢
29	A42,D42,E40 Fire Siren	1	30,094	515	1	3,009.4000¢
30	A43 St. Anthony Dam	511	32,369			6.3344¢
31	UNBILLED	58	5,939			10.2396¢
32	TOTAL Other Sales	135,009	8,096,22[illegible]	2,517	53,638	5.9968¢
33						
34						
35	Interdepartmental Sales	17,325	812,806			4.6915¢
36	TOTAL Interdepartmental Sales	17,325	812,806	0		4.6915¢
37						
38						
39						
40						
41	Total Billed	29,548,901	* $1,689,043,921			5.7160¢
42	Total Unbilled Rev.(See Instr. 6)	172,649	* $9,133,530			5.2902¢
43	TOTAL	29,721,550	$1,698,177,451	1,199,895	24,770	5.7136¢

< Page 304 Line 1 Column d >

Indicates duplicate customers

< Page 304 Line 6 Column d >

Indicates duplicate customers

< Page 304 Line 7 Column d >

Indicates duplicate customers

< Page 304 Line 8 Column d >

Indicates duplicate customers

< Page 304 Line 9 Column d >

Indicates duplicate customers

< Page 304 Line 17 Column d >

Indicates duplicate customers

< Page 304 Line 22 Column d >

Indicates duplicate customers

< Page 304 Line 23 Column d >

Indicates duplicate customers

< Page 304 Line 24 Column d >

Indicates duplicate customers

< Page 304 Line 27 Column d >

Indicates duplicate customers

< Page 304.1 Line 1 Column d >

Indicates duplicate customers

< Page 304.1 Line 41 Column c >

Revenues include billed Fuel Clause revenues of ($6,825,161)
for total Ultimate Customers.

< Page 304.1 Line 42 Column c >

Does not include Sales for Resale Unbilled Revenue

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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

LF - for 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 seller 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 desgnated 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	City of Ada	RQ	474	1105	2828	
2	City of Anoka	RQ	420			
3	City of Arlington	RQ	421			
4	City of Brownton	RQ	422			
5	City of Buffalo	RQ	475	11449	11660	
6	City of Chaska	RQ	424			
7	City of East Grand Forks	RQ	476	9121	21175	
8	City of Fairfax	RQ	477	692	2354	
9	City of Kasota	RQ	426	677	677	
10	City of Kasson	RQ	479	3772	3772	
11	City of LeSueur	RQ	392	7881	7881	
12	City of Madelia	RQ	481	5322	5290	
13	City of Melrose	RQ	482	9160	14656	
14	City of North St. Paul	RQ	429			

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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 exptanations following all required data.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
6,534	$79,520	$161,264	$842	$241,626	1
			(678)	(678)	2
			(45)	(45)	3
			(15)	(15)	4
68,653	968,140	1,654,616	15,741	2,638,497	5
			(503)	(503)	6
48,604	496,300	1,180,739	1,296	1,678,335	7
6,939	51,807	93,943	2,033	147,783	8
3,286	55,908	81,096	2,301	139,305	9
20,002	330,555	493,039	6,046	829,640	10
46,017	734,527	1,006,852	(4,599)	1,736,780	11
29,164	435,546	703,675	8,745	1,147,966	12
63,464	748,763	1,506,168	15,678	2,270,609	13
			(217)	(217)	14

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

LF - for 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 seller 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.

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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 desgnated 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	City of Olivia	RQ	388	476	2443	
2	City of Shakopee	RQ	498	26528	26528	
3	City of Sioux Falls	RQ	484	4591	11589	
4	City of Winthrop	RQ	433			
5	Northern States Power Co. (WI)	RQ	363	NA	NA	
6	Unbilled Revenue					
7	SUBTOTAL-RQ			*	*	
8	Interstate Power Co	*	417	NA	NA	NA
9	IES Utilities	*	417	NA	NA	NA
10	Kansas City Power & Light	*	417	NA	NA	NA
11	Lincoln Elec System	*	417	NA	NA	NA
12	MidAmerican Energy Company	*	417	NA	NA	NA
13	Madison Gas & Electric	*	460	NA	NA	NA
14	Minnesota Power Company	*	417	NA	NA	NA

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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

Megawatthours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
2,509	$49,897	$54,886	$783	$105,566	1
	149,617		(409)	149,208	2
29,804	393,759	729,239	(5,992)	1,117,006	3
			(49)	(49)	4
5,315,275			173,395,508	* 173,395,508	5
(16,809)		(411,942)		(411,942)	6
5,623,442	4,494,339	7,253,575	* 173,436,466	185,184,380	7
6,667		99,037		99,037	8
19,517		310,431		310,431	9
81,455		1,261,625		1,261,625	10
5,135		69,471		69,471	11
8,037		119,426		119,426	12
2,058		38,703		38,703	13
46,474		592,663		592,663	14

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

LF - for 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 seller 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 desgnated 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)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Missouri Basin	*	417	NA	NA	NA
2	Missouri Public Service	*	417	NA	NA	NA
3	Montana-Dakota	*	417	NA	NA	NA
4	Municipal Energy Agency of Nebraska	*	Co-Gen	NA	NA	NA
5	Muscatine Power & Water	*	417	NA	NA	NA
6	Nebraska Pub Power Dist	*	417	NA	NA	NA
7	North Central Power	*	417	NA	NA	NA
8	NoWestern Pub Serv Co	*	417	NA	NA	NA
9	NoWestern Wis Electric	*	417	NA	NA	NA
10	Omaha Pub Pwr Dist	*	417	NA	NA	NA
11	Otter Tail Pwr Co	*	417	NA	NA	NA
12	St Joseph Lt & Pwr Co	*	351	NA	NA	NA
13	So Mn Mun Pwr Agency	*	417	NA	NA	NA
14	Union Electric Co	*	321	NA	NA	NA

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

Megawatthours Sold (g)	REVENUE: Demand Charges ($) (h)		Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
16,655			$1,146,934		$1,146,934	1
1,520			16,792		16,792	2
1,597			18,945		18,945	3
222			4,121		4,121	4
1,025			13,084		13,084	5
52,146			812,808		812,808	6
18,099	163,700	*	399,886		563,586	7
6,441			99,510		99,510	8
147,612	742,925	*	3,296,728		4,039,653	9
17,679			287,020		287,020	10
8,985			158,964		158,964	11
11,043			190,409		190,409	12
7,233			99,388		99,388	13
815,350	489,507		10,618,524		11,108,031	14

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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

LF - for 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 seller 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 desgnated 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)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Upper Peninsula Power Co	*	517	NA	NA	NA
2	Wisconsin Electric Power Co	*	319	NA	NA	NA
3	Wisconsin Pub Power Inc Sys	*	447	NA	NA	NA
4	Wisconsin Pub Service Corp	*	346	NA	NA	NA
5	Wisconsin Power & Light Co	*	410	NA	NA	NA
6	Wisconsin Rapids WWLC	*	NSP Op.Co.4	NA	NA	NA
7	Basin Electric Coop	*	417	NA	NA	NA
8	Coop Power Association	*	417	NA	NA	NA
9	Dairyland Power Coop	*	417	NA	NA	NA
10	Enron Power Marketing Inc.	*	NSP Op.Co.36	NA	NA	NA
11	Hutchinson Utilities	*	434	NA	NA	NA
12	Minnkota Power Coop	*	417	NA	NA	NA
13	Manitoba Hydro	*	359	NA	NA	NA
14	United Power Association	*	417	NA	NA	NA

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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
96,531		$1,261,010		$1,261,010	1
575,440	741,500	8,550,964		9,292,464	2
208,863	75,500	2,651,383		2,726,883	3
842,272	1,963,257	14,362,118		16,325,375	4
455,215	189,487	5,713,876		5,903,363	5
2,720	285,000	71,127		356,127	6
656		18,594		18,594	7
11,101		160,236		160,236	8
28,420		470,437		470,437	9
68,141	62,400	918,148		980,548	10
772		11,479		11,479	11
60,486		977,352		977,352	12
59,351		763,520		763,520	13
85,135	235,000	* 1,393,035		1,628,035	14

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity,etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (page 326-327).

2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

LF - for 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 seller 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.

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IU - for intermediate-term service from a desgnated 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)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Western Area Power Admin	*	446	NA	NA	NA
2	City of Delano	*	470	NA	NA	NA
3	City of Janesville	*	470	NA	NA	NA
4	City of Lake Crystal	*	470	NA	NA	NA
5	City of Glencoe	*	470	NA	NA	NA
6	City of Mountain Lake	*	470	NA	NA	NA
7	City of Truman	*	470	NA	NA	NA
8	City of Kenyon	*	470	NA	NA	NA
9	City of New Ulm	*	398	NA	NA	NA
10	City of Sleepy Eye	*	393	NA	NA	NA
11	City of Blue Earth	*	485	NA	NA	NA
12	City of East Grand Forks	*	476	NA	NA	NA
13	SUBTOTAL-NON-RQ					
14	TOTAL					

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 (g) 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 megawatthours 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 subtotalled based on the RQ/Non-RQ grouping (see instruction 4), and then totalled 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.

Megawatthours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total($) (h+i+j) (k)	Line No.
30,803		$379,858		$379,858	1
30,844		564,537		564,537	2
9,888		182,781		182,781	3
14,328		268,848		268,848	4
76,820		1,367,366		1,367,366	5
11,502		224,661		224,661	6
13,267		248,127		248,127	7
13,905	117,756	265,022		382,778	8
145,325		* 2,960,599		2,960,599	9
24,112	78,809	501,704		580,513	10
10,568		280,838		280,838	11
12,444	144,558	269,168		413,726	12
4,163,859	5,289,399	64,491,257	0	69,780,656	13
* 9,787,301	9,783,738	71,744,832	173,436,466	* 254,965,036	14

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< Page 310.1 Line 7 Column d >

15 Minute Integration

< Page 310.1 Line 7 Column e >

15 Minute Integration

< Page 310.1 Line 8 Column b >

OS - Economy, Schedule M, Scheduled Outage, Emergency

< Page 310.1 Line 9 Column b >

OS - Economy, Emergency, Schedule M, Term, Scheduled Outage

< Page 310.1 Line 10 Column b >

OS - Schedule M, Term

< Page 310.1 Line 11 Column b >

OS - Schedule M, Scheduled Outage

< Page 310.1 Line 12 Column b >

OS - Economy, Emergency, Schedule M, Scheduled Outage

< Page 310.1 Line 13 Column b >

OS - Economy, General Purpose

< Page 310.1 Line 14 Column b >

OS - Economy, Emergency, Schedule M

< Page 310.2 Line 1 Column b >

OS - Schedule M, Operating Reserve

< Page 310.2 Line 2 Column b >

OS - Schedule M

< Page 310.2 Line 3 Column b >

OS - Economy, Schedule M, Emergency

< Page 310.2 Line 4 Column b >

OS - Schedule M

< Page 310.2 Line 5 Column b >

OS - Scheduled Outage, Schedule M

< Page 310.2 Line 6 Column b >

OS - Economy, Emergency, Schedule M, Scheduled Outage

< Page 310.2 Line 7 Column b >

OS - Peaking, System Power, Supplemental Power

< Page 310.2 Line 8 Column b >

OS - Economy, Emergency, Schedule M

< Page 310.2 Line 9 Column b >

OS - Supplemental Power, System Power

< Page 310.2 Line 10 Column b >

OS - Economy, Emergency, Schedule M, Scheduled Outage

< Page 310.2 Line 11 Column b >

OS - Economy, Schedule M, System Power, Emergency, Scheduled Outage

< Page 310.2 Line 12 Column b >

OS - Schedule M, Term, Excess

< Page 310.2 Line 13 Column b >

OS - Economy, Emergency, Schedule M, Scheduled Outage

< Page 310.2 Line 14 Column b >

OS - Excess, Term, Short-term

< Page 310.3 Line 1 Column b >

OS - Supplemental Power, General Purpose

< Page 310.3 Line 2 Column b >

OS - Economy, General Purpose, Supplemental Power, Short-term, System Power

< Page 310.3 Line 3 Column b >

OS - Economy, General Purpose, Schedule M, Supplemental Power, Emergency, Scheduled Outage, Short-term

< Page 310.3 Line 4 Column b >

OS - Economy, Reserve, Supplemental Power, General Purpose

< Page 310.3 Line 5 Column b >

OS - Economy, General Purpose, Schedule M, Long-term

< Page 310.3 Line 6 Column b >

OS - Firm

< Page 310.3 Line 7 Column b >

OS - Emergency, Schedule M

< Page 310.3 Line 8 Column b >

OS - Economy, Emergency, Schedule M

< Page 310.3 Line 9 Column b >

OS - Economy, Emergency, Schedule M, Operational Control, Scheduled Outage

< Page 310.3 Line 10 Column b >

OS - Firm, System Power, Supplemental Power

< Page 310.3 Line 11 Column b >

OS - Emergency, Schedule M

< Page 310.3 Line 12 Column b >

OS - Economy, Schedule M, Participation Power, Emergency

< Page 310.3 Line 13 Column b >

OS - Operational Control, Scheduled Outage, Seasonal Diversity

< Page 310.3 Line 14 Column b >

OS - Economy, Emergency, Firm, Schedule M, Participation Power, Scheduled Outage

< Page 310.4 Line 1 Column b >

OS - Economy, Schedule M, Scheduled Outage

< Page 310.4 Line 2 Column b >

OS - Economy

< Page 310.4 Line 3 Column b >

OS - Economy

< Page 310.4 Line 4 Column b >

OS - Economy

< Page 310.4 Line 5 Column b >

OS - Economy

< Page 310.4 Line 6 Column b >

OS - Economy

< Page 310.4 Line 7 Column b >

OS - Economy

< Page 310.4 Line 8 Column b >

OS - Economy, Peaking

< Page 310.4 Line 9 Column b >

OS - Economy

< Page 310.4 Line 10 Column b >

OS - Peaking, Short-term

< Page 310.4 Line 11 Column b >

OS - Supplemental

< Page 310.4 Line 12 Column b >

OS - Base Load

< Page 311.1 Line 5 Column k >

Total Dollars and MWHs will not match page 300/301, line 10, due to differences in accounting classification associated with the NSP Minnesota and Wisconsin company Interchange Agreement (see note 10 of Notes to the Financial Statements).

< Page 311.1 Line 7 Column j >

Includes Fuel Clause Adjustment, Customer Charge, refund for DOE Nuclear Fuel Disposal credit on Westmoreland Production Tax Payments, Docket No. EL94-94-000, and reimbursement to NSP-Wisconsin for production and transmission costs shared under the Interchange Agreement.

< Page 311.2 Line 7 Column i >

Total energy charges include $13,279 of transmission charges for October through December. These bills were unbundled.

< Page 311.2 Line 9 Column i >

Total energy charges include $69,469 of transmission charges for October through December. These bills were unbundled.

< Page 311.3 Line 14 Column i >

Includes a ($17,154) discrepancy that will be reflected in the general ledger in 1997.

< Page 311.4 Line 9 Column i >

Total energy charges include $340,482 of transmission charges for January-December. These bills were unbundled. There is also a ($182,262) discrepancy that will be reflected in the general ledger in 1997.

< Page 311.4 Line 14 Column g >

Total dollars and MWHs will not match page 300/301, line 11, due to differences in accounting classification associated with the NSP Minnesota and Wisconsin company Interchange Agreement (see note 10 of Notes to the Financial Statements).

< Page 311.4 Line 14 Column k >

Total dollars and MWHs will not match page 300/301, line 11, due to differences in accounting classification associated with the NSP Minnesota and Wisconsin company Interchange Agreement (see note 10 of Notes to the Financial Statements).

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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

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	$8,179,793	$8,689,903
5	(501) Fuel	231,957,725	252,730,815
6	(502) Steam Expenses	16,506,337	16,822,192
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred--Cr.		
9	(505) Electric Expenses	4,365,319	4,685,579
10	(506) Miscellaneous Steam Power Expenses	19,725,758	21,083,155
11	(507) Rents	151,540	151,927
12	(509) Allowance		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	$280,886,472	$304,163,571
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	$5,220,881	$5,730,141
16	(511) Maintenance of Structures	3,068,481	1,952,184
17	(512) Maintenance of Boiler Plant	22,511,767	25,419,774
18	(513) Maintenance of Electric Plant	7,392,152	7,391,398
19	(514) Maintenance of Miscellaneous Steam Plant	3,505,948	4,232,299
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	$41,699,229	$44,725,796
21	TOTAL Power Production Expenses--Steam Power (Enter Total of lines 13 and 20)	$322,585,701	$348,889,367
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	$21,121,793	$24,748,454
25	(518) Fuel	61,084,976	67,131,235
26	(519) Coolants and Water	640,147	341,488
27	(520) Steam Expenses	16,812,811	12,904,613
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred--Cr.		
30	(523) Electric Expenses	7,257,601	7,184,417
31	(524) Miscellaneous Nuclear Power Expenses	44,412,919	44,631,758
32	(525) Rents	492,342	414,923
33	TOTAL Operation (Enter Total of lines 24 thru 32)	$151,822,589	$157,356,888
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	$3,349,460	$2,639,653
36	(529) Maintenance of Structures	807,503	1,266,756
37	(530) Maintenance of Reactor Plant Equipment	13,241,082	9,864,510
38	(531) Maintenance of Electric Plant	5,426,676	5,058,714
39	(532) Maintenance of Miscellaneous Nuclear Plant	9,937,061	8,449,346
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	$32,761,782	$27,278,979
41	TOTAL Power Production Expenses--Nuclear Power (Enter total of lines 33 and 40)	$184,584,371	$184,635,867
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	$132,609	$145,606
45	(536) Water for power	105,956	113,825
46	(537) Hydraulic Expenses	52,887	54,618
47	(538) Electric Expenses	59,064	45,526
48	(539) Miscellaneous Hydraulic Power Generation Expenses	157,015	158,801
49	(540) Rents	1,040	2,037
50	TOTAL Operation (Enter Total of lines 44 thru 49)	$508,571	$520,413

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

ELECTRIC OPERATION AND MAINTENANCE EXPENSES(Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$25,500	$30,706
54	(542) Maintenance of Structures	2,917	40,726
55	(543) Maintenance of Reservoirs, Dams, and Waterways	4,176	33,279
56	(544) Maintenance of Electric Plant	5,600	12,036
57	(545) Maintenance of Miscellaneous Hydraulic Plant	29,083	2,805
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	$67,276	$119,552
59	TOTAL Power Production Expenses-Hydraulic Power(Enter total of lines 50 and 58)	$575,847	$639,965
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	$199,581	$258,682
63	(547) Fuel	2,993,171	2,903,218
64	(548) Generation Expenses	345,993	319,171
65	(549) Miscellaneous Other Power Generation Expenses	410,761	462,836
66	(550) Rents	7,168	7,184
67	TOTAL Operation (Enter Total of lines 62 thru 66)	$3,956,674	$3,951,091
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	$96,237	$223,910
70	(552) Maintenance of Structures	60,751	69,936
71	(553) Maintenance of Generating and Electric Plant	804,370	663,049
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	124,681	457,943
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	$1,086,039	$1,414,838
74	TOTAL Power Production Expenses--Other Power (Enter Total of lines 67 and 73)	$5,042,713	$5,365,929
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	$239,969,781	$244,923,190
77	(556) System Control and Load Dispatching	1,592,919	1,222,493
78	(557) Other Expenses	* 47,099,490	47,945,467
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	$288,662,190	$294,091,150
80	TOTAL Power Production Expenses (Enter Total of lines 21,41,59,74,and 79)	$801,450,822	$833,622,278
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervison and Engineering	$2,323,053	$2,689,688
84	(561) Load Dispatching	3,896,342	3,701,189
85	(562) Station Expenses	740,686	845,992
86	(563) Overhead Lines Expenses	715,338	701,780
87	(564) Underground Lines Expenses	29,935	62,720
88	(565) Transmission of Electricity by Others	6,909,305	3,402,507
89	(566) Miscellaneous Transmission Expenses	* 25,471,657	25,497,205
90	(567) Rents	511,227	672,058
91	TOTAL Operation (Enter Total of lines 83 thru 90)	$40,597,543	$37,573,139
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	$264,444	$333,908
94	(569) Maintenance of Structures	39,068	29,851
95	(570) Maintenance of Station Equipment	4,228,978	4,348,500
96	(571) Maintenance of Overhead Lines	3,377,725	5,035,427
97	(572) Maintenance of Underground Lines	26,160	23,131
98	(573) Maintenance of Miscellaneous Transmission Plant	1,300,860	1,260,828
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	$9,237,235	$11,031,645
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	$49,834,778	$48,604,784
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	$3,344,126	$3,479,834

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount For Previous Year (c)
104	3. DISTRIBUTION Expenses (Continued)		
105	(581) Load Dispatching	$3,401,203	$3,629,613
106	(582) Station Expenses	1,426,399	1,448,734
107	(583) Overhead Line Expenses	4,453,972	4,426,340
108	(584) Underground Line Expenses	5,025,622	4,304,244
109	(585) Street Lighting and Signal System Expenses	294,884	356,463
110	(586) Meter Expenses	3,614,433	2,849,594
111	(587) Customer Installations Expenses	438,069	511,498
112	(588) Miscellaneous Expenses	14,083,925	15,472,685
113	(589) Rents	1,057,201	972,191
114	TOTAL Operation (Enter Total of lines 103 thru 113)	$37,139,834	$37,451,196
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	$324,339	$468,190
117	(591) Maintenance of Structures	502,227	324,088
118	(592) Maintenance of Station Equipment	5,011,468	6,987,038
119	(593) Maintenance of Overhead Lines	27,538,603	27,944,756
120	(594) Maintenance of Underground Lines	4,156,162	3,413,381
121	(595) Maintenance of Line Transformers	1,047,682	1,009,587
122	(596) Maintenance of Street Lighting and Signal Systems	1,938,624	1,724,785
123	(597) Maintenance of Meters	22,287	61,829
124	(598) Maintenance of Miscellaneous Distribution Plant	268,681	374,616
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	$40,810,073	$42,308,270
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	$77,949,907	$79,759,466
127	4.CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	$2,115,110	$1,450,815
130	(902) Meter Reading Expenses	9,491,751	9,672,710
131	(903) Customer Records and Collection Expenses	14,494,046	13,914,964
132	(904) Uncollectible Accounts	12,546,284	5,951,179
133	(905) Miscellaneous Customer Accounts Expenses	5,148,371	4,451,943
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	$43,795,562	$35,441,611
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	$14,686	$18,1[illegible]6
138	(908) Customer Assistance Expenses	57,770,042	45,163,044
139	(909) Information and Instructional Expenses	833,057	1,078,867
140	(910) Miscellaneous Customer Service and Information Expenses	10,885,930	8,558,690
141	TOTAL Cust. Service and Informational Exp.(Enter Total of lines 137 thru 140)	$69,503,715	$54,818,767
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		
145	(912) Demonstrating and Selling Expenses	1,421,934	1,127,192
146	(913) Advertising Expenses		
147	(916) Miscellaneous Sales Expenses	84,645	83,501
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	$1,506,579	$1,210,693
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	$44,055,743	$47,637,219
152	(921) Office Supplies and Expenses	14,006,777	23,851,605
153	(Less) (922) Administrative Expenses Transferred--Credit	7,318,939	7,962,439

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$2,347,285	$2,076,814
156	(924) Property Insurance	(316,381)	5,686,118
157	(925) Injuries and Damages	8,461,854	9,900,177
158	(926) Employee Pensions and Benefits	48,949,723	61,677,800
159	(927) Franchise Requirements	64,194	24,609
160	(928) Regulatory Commission Expenses	3,827,433	3,404,156
161	(929) (Less) Duplicate Charges--Cr.	2,850,290	992,662
162	(930.1) General Advertising Expenses	2,248,217	1,261,152
163	(930.2) Miscellaneous General Expenses	3,888,297	6,709,989
164	(931) Rents	3,448,281	3,585,430
165	TOTAL Operation (Enter Total of lines 151 Thru 164)	$120,812,194	$156,859,968
166	Maintenance		
167	(935) Maintenance of General Plant	$55,403	$141,247
168	TOTAL Administrative and General Expenses (Enter total of lines 165 thru 167)	$120,867,597	$157,001,215
169	TOTAL Electric Operation and Maintenance Expenses (Enter total of lines 80,100,126,134,141,148 and 168)	$1,164,908,960	$1,210,458,814

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.

2. If the respondent's payroll for the reporting period includes any special construction personel, include such employees on line 3, and show the number of such special construction employees in a footnote.

3. The number of employees assignable to the electric department from joint functions of combination utilities may be dete mined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1. Payroll Period Ended (Date)	12/31/96	
2. Total Regular Full-Time Employees		4,608
3. Total Part-Time and Temporary Employees		662
4. Total Employees *		5,270

< Page 321 Line 78 Column b >

Includes $37,832,096 of Fixed Costs and $7,491,393 of Variable Costs reimbursed to Northern States Power Company (Wisconsin), a subsidiary company, for production costs shared through an Interchange Agreement.

< Page 321 Line 89 Column b >

Includes $24,013,537 of Fixed Costs reimbursed to Northern States Power Company (Wisconsin), a subsidiary company, for transmission costs shared through an Interchange Agreement.

< Page 323 >

Estimated number of employees attributed to electric department from joint functions - 949.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. lso 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 projected load for this service in its system resource planning). In addition, the reliablility 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 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 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.

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 (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Basin Electric Power Coop	*	417	NA	NA	NA
2	Cooperative Power Association	*	417	NA	NA	NA
3	Dairyland Power Coop	*	417	NA	NA	NA
4	Enron Power Marketing Inc.	*	NSP Op.Co.36	NA	NA	NA
5	Hutchinson Utilities	*	434	NA	NA	NA
6	Interstate Power Co	*	417	NA	NA	NA
7	IES Utilities	*	417	NA	NA	NA
8	Kansas City Power & Light	*	417	NA	NA	NA
9	Lincoln Electric Sys	*	417	NA	NA	NA
10	Manitoba Hydro	*	359	NA	NA	NA
11	MidAmerican Energy Company	*	417	NA	NA	NA
12	Minnesota Power	*	417	NA	NA	NA
13	Minnkota Power Coop	*	417	NA	NA	NA
14	Minnkota Power Coop	*	417	NA	NA	NA

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm 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.

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 nonFERC 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 services 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 column (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 (1) 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.

Megawatthours Purchased (g)	POWER EXCHANGES: Megawatthours Received (h)	Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
108,131				$1,621,741	$5,808	$1,627,549	1
10,533				240,923	1,301	242,224	2
43,326				659,211	1,744	660,955	3
800				26,400		26,400	4
655				11,336	1	11,337	5
5,495				181,305	589	181,894	6
4,006				74,483	3,801	78,284	7
56,586				1,393,121	38,663	1,431,784	8
21,015				503,701	3,021	506,722	9
5,916,024			* 61,410,859	88,677,182	398,318	150,486,359	10
190,416			1,224,000	4,393,192	44,374	5,661,566	11
465,322			2,151,453	8,129,207	1,943	10,282,603	12
577,219			* 16,212,838	6,471,156	6,623	22,690,617	13
		32,865				0	14

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. lso report exchanges of electricity (i.e. transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced excnanges.
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 projected load for this service in its system resource planning). In addition, the reliablility 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 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 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.

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 (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Missouri Basin Municipal Power	*	417	NA	NA	NA
2	Missouri Basin Municipal Power	*	417	NA	NA	NA
3	Montana-Dakota Util	*	417	NA	NA	NA
4	Municipal Energy Agency of Nebraska	*	Co-gen	NA	NA	NA
5	Muscatine Power & Water	*	417	NA	NA	NA
6	Nebraska Public Power Dist	*	417	NA	NA	NA
7	Nobles Electric	*	*	NA	NA	NA
8	Northwestern Public Service	*	417	NA	NA	NA
9	Northwestern WI Electric	*	417	NA	NA	NA
10	Omaha Public Power Dist	*	417	NA	NA	NA
11	Otter Tail Power	*	417	NA	NA	NA
12	Southern MN Municipal Power	*	417	NA	NA	NA
13	St. Joseph Light & Power	*	351	NA	NA	NA
14	Union Electric	*	321	NA	NA	NA

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

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm 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.

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4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for nonFERC 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 services 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 column (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 (1) 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.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
134,137				$1,912,343	$30,352	$1,942,695	1
	7,428					0	2
52,231				837,177	21,416	858,593	3
150				2,700		2,700	4
4,680				70,807	365	71,172	5
37,633				660,152	7,804	667,956	6
93				3,581		3,581	7
841				12,152	10	12,162	8
159				23,835		23,835	9
23,493				546,413	16,285	562,698	10
73,166				1,307,661	13,168	1,320,829	11
9,315				154,345	159	154,504	12
3,020				80,513	1,831	82,344	13
208,362				5,144,063	78,097	5,222,160	14

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made dur'ng the year. lso 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 projected load for this service in its system resource planning). In addition, the reliablility 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 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 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.

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 (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	United Power Assoc	*	417	NA	NA	NA
2	United Power Assoc	*	417	NA	NA	NA
3	Western Area Power Admin	*	446	NA	NA	NA
4	Western Area Power Admin	*	446	NA	NA	NA
5	WI Electric Power Co	*	319	NA	NA	NA
6	Commonwealth Edison	*	*	NA	NA	NA
7	WI Power & Light	*	410	NA	NA	NA
8	WI Public Power Inc Sys	*	447	NA	NA	NA
9	WI Public Service Corp	*	346	NA	NA	NA
10	City of Blue Earth	*	485	NA	NA	NA
11	Barron County Waste	*	IPP	NA	NA	NA
12	Windpower Partners 1993 LP	*	IPP	NA	NA	NA
13	Byllesby Dam	*	IPP	NA	NA	NA
14	Chippewa Reservoir Power	*	IPP	NA	NA	NA

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm 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.

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 nonFERC 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 services 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 column (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 (1) 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.

Megawatthours Purchased (g)	POWER EXCHANGES: Megawatthours Received (h)	POWER EXCHANGES: Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
26,906				$519,698	$615	$520,313	1
	11,047	48				0	2
252,332				4,158,783	15,656	4,174,439	3
	31,848					0	4
14,906				501,717	4,690	506,407	5
10,587				286,763		286,763	6
48,938				1,129,303	16,360	1,145,663	7
481				14,734		14,734	8
1,849				68,521	570	69,091	9
773				6,893		6,893	10
3				82		82	11
50,090				2,829,545		2,829,545	12
11,254			412,315	219,792		632,107	13
11,718			465,594	250,185		715,779	14

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 projected 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 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 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.

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 (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Cypress Silver Bay Power Co	*	IPP	NA	NA	NA
2	Eau Galle Renew Energy Co	*	IPP	NA	NA	NA
3	Ford Motor Co	*	IPP	NA	NA	NA
4	Hastings Lock & Dam	*	IPP	NA	NA	NA
5	Heartland Consumers Pwr District	*	471	NA	NA	NA
6	Hennepin Energy Resource Recov	*	IPP	NA	NA	NA
7	Minnesota Methane Company LLC	*	IPP	NA	NA	NA
8	Landfill Power LLC	*	IPP	NA	NA	NA
9	Browning-Ferris Gas Services, Inc.	*	IPP	NA	NA	NA
10	Neshkoro Power Association	*	IPP	NA	NA	NA
11	Actacon-Rapidan	*	IPP	NA	NA	NA
12	St. Cloud Hydro	*	IPP	NA	NA	NA
13	Alfred Jessen	*	IPP	NA	NA	NA
14	Lester Vandenberg	*	IPP	NA	NA	NA

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm 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.

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 nonFERC 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 services 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 column (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 (1) 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.

	POWER EXCHANGES		COST/SETTLEMENT OF POWER				
Megawatthours Purchased (g)	Megawatthours Received (h)	Megawatthours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
43,160			$6,132,174	$965,737		$7,097,911	1
1,183				74,731		74,731	2
33,346				501,318		501,318	3
16,095			404,125	210,283		614,408	4
4,136				53,262		53,262	5
197,970			8,101,967	2,218,571		10,320,538	6
23,[illegible]			312,304	381,882		694,186	7
26,677			555,311	416,600		971,911	8
39,840			576,032	600,091		* 1,176,123	9
2,493			76,473	58,357		134,830	10
13,506			377,583	150,532		528,115	11
53,763			1,332,573	744,828		2,077,401	12
27				1,762		1,762	13
7				344		344	14

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. iso report exchanges of electricity (i.e. transactions involving a balan[illegible] debits and credits for energy, capacity, [illegible] and any settlements for imbalanced exchang[illegible]
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 projected 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 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 seller 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 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.

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 (d)	Actual Demand(MW) Average Monthly NCP Demand (e)	Actual Demand(MW) Average Monthly CP Demand (f)
1	Robert Hedin	*	IPP	NA	NA	NA
2	District Energy	*	Co-Gen	NA	NA	NA
3	Northern States Power Co (WI)	RQ	363	NA	NA	NA
4	Mid-Continent Area Power Pool	*	MAPP	NA	NA	NA
5	Minnesota Municipal Power Assoc	*	TM-1	NA	NA	NA
6	TOTAL					
7						
8						
9						
10						
11						
12						
13						
14						

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (X) An Original ( ) A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm 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.

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 nonFERC 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 services 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 column (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 (1) 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.

Megawatthours Purchased (g)	POWER EXCHANGES: Megawatthours Received (h)	POWER EXCHANGES: Megawatthours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
1				$9		$9	1
472				7,593		7,593	2
412,925					45,323,489	* 45,323,489	3
	143,228	5,812					4
	15,923	78					5
9,246,297	209,474	38,803	99,745,601	139,510,616	* 46,037,053	* 285,293,270	6
							7
							8
							9
							10
							11
							12
							13
							14

< Page 326 Line 1 Column b >

OS - Schedule M, Scheduled Outage

< Page 326 Line 2 Column b >

OS - Emergency, Schedule M

< Page 326 Line 3 Column b >

OS - Class B, Emergency, Schedule M, Scheduled Outage

< Page 326 Line 4 Column b >

Schedule M

< Page 326 Line 5 Column b >

OS - Emergency, Schedule M

< Page 326 Line 6 Column b >

OS - Emergency, Schedule M

< Page 326 Line 7 Column b >

OS - Emergency, Schedule M

< Page 326 Line 8 Column b >

OS - Scheduled Outage, Term, Schedule M

< Page 326 Line 9 Column b >

OS - Economy, Schedule M

< Page 326 Line 10 Column b >

OS - Operational Control, Peaking, Participation

Power, Seasonal Diversity, Scheduled Outage, Tertiary, System Power

< Page 326 Line 11 Column b >

OS - Schedule M, Short-term, Emergency, Firm, Scheduled Outage

< Page 326 Line 12 Column b >

OS - Emergency, Firm, Schedule M, Operating Reserve

< Page 326 Line 13 Column b >

OS - Economy, Emergency, Schedule M, Participation Power

< Page 326 Line 14 Column b >

EX - Losses due to Coyote Schedule

< Page 326.1 Line 1 Column b >

OS - Schedule M

< Page 326.1 Line 2 Column b >

EX - Compensation for losses at Splitrock

< Page 326.1 Line 3 Column b >

OS - Economy, Emergency, Schedule M, Schedule Outage

< Page 326.1 Line 4 Column b >

Schedule M

< Page 326.1 Line 5 Column b >

OS - Emergency, Schedule M

< Page 326.1 Line 6 Column b >

OS - Emergency, Schedule M, Scheduled Outage, System Power

< Page 326.1 Line 7 Column b >

OS - Base Load

< Page 326.1 Line 7 Column c >

It was not necessary for NSP to file this contract since NSP's only transaction with them was a purchase.

< Page 326.1 Line 8 Column b >

OS - Economy, Emergency, Schedule M

< Page 326.1 Line 9 Column b >

OS - Operational Control

< Page 326.1 Line 10 Column b >

OS - Emergency, Schedule M

< Page 326.1 Line 11 Column b >

OS - Economy, Emergency, Schedule M, System Power

< Page 326.1 Line 12 Column b >

OS - Emergency, Schedule M, Economy, Operational Control

< Page 326.1 Line 13 Column b >

OS - Excess, Term

< Page 326.1 Line 14 Column b >

OS - Excess, Term

< Page 326.2 Line 1 Column b >

OS - Emergency, Schedule M, Participation Power

< Page 326.2 Line 2 Column b >

EX - Due to Joint Transmission Network Agreement

< Page 326.2 Line 3 Column b >

OS - Economy, Emergency, Schedule M, Scheduled Outage

< Page 326.2 Line 4 Column b >

EX - WAPA losses due to Wheeling

< Page 326.2 Line 5 Column b >

OS - General Purpose, Interruptible Replacement Supplemental, Losses

< Page 326.2 Line 6 Column b >

OS - General Purpose

< Page 326.2 Line 6 Column c >

It was not necessary to file this contract since NSP's only transactions with them were purchases.

< Page 326.2 Line 7 Column b >

OS - General Purpose

< Page 326.2 Line 8 Column b >

OS - Emergency, General Purpose, Schedule M

< Page 326.2 Line 9 Column b >

OS - General Purpose, Supplemental

< Page 326.2 Line 10 Column b >

OS - Dump Energy

< Page 326.2 Line 11 Column b >

OS - Base Load

< Page 326.2 Line 12 Column b >

OS - Base Load

< Page 326.2 Line 13 Column b >

OS - Base Load

< Page 326.2 Line 14 Column b >

OS - Base Load

< Page 326.3 Line 1 Column b >

OS - Participation Power

< Page 326.3 Line 2 Column b >

OS - Base Load

< Page 326.3 Line 3 Column b >

OS - Excess

< Page 326.3 Line 4 Column b >

OS - Base Load, Excess

< Page 326.3 Line 5 Column b >

OS - Schedule M

< Page 326.3 Line 6 Column b >

OS - Base Load

< Page 326.3 Line 7 Column b >

OS - Base Load

< Page 326.3 Line 8 Column b >

OS - Base Load

< Page 326.3 Line 9 Column b >

OS - Base Load

< Page 326.3 Line 10 Column b >

OS - Base Load

< Page 326.3 Line 11 Column b >

OS - Base Load, Excess, Peaking

< Page 326.3 Line 12 Column b >

OS - Base Load

< Page 326.3 Line 13 Column b >

OS - Windmill Energy

< Page 326.3 Line 14 Column b >

OS - Windmill Energy

< Page 326.4 Line 1 Column b >

OS - Windmill Energy

< Page 326.4 Line 2 Column b >

OS - Steam Driven Energy

< Page 326.4 Line 4 Column b >

EX - Due to MAPP Loss Repayment Procedure

< Page 326.4 Line 5 Column b >

EX - Pooltie implementation was not complete.
A separate temporary schedule was created.

< Page 327 Line 10 Column j >

Includes a reversal of an accrual, and a payment to Manitoba Hydro for a dispute on the Participation Power contract.

< Page 327 Line 13 Column j >

Includes an accrual for possible increase in capacity payments.

< Page 327.3 Line 9 Column m >

Total dollars are an accrual for February-December 1996. Actual invoices have not been received or paid as yet by NSP.

< Page 327.4 Line 3 Column m >

Total dollars will not match page 321 line 76 due to differences in accounting classification of dollars associated with the interchange agreement between the Minnesota and Wisconsin companies (see Note 10 of the Notes to Financial Statements).

< Page 327.4 Line 6 Column l >

The charges in Col L (except from Northern States Power Co. (WI)) represent the Mid-Continent Area Power Pool's (MAPP) transmission service charge based on energy demand purchases.

< Page 327.4 Line 6 Column m >

Total Dollars will not match page 321, line 76 due to differences in accounting classification of dollars associated with the interchange agreement between the Minnesota and Wisconsin companies (see Note 10 of the Notes to Financial Statements).

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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

1. Report all transmission of electricity, i. e. wheeling, provided for other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
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:

LF - for long-term firm transmission service. "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 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.

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

Line No.	Payment By (Company or Public Authority) [Footnote Affiliations] (a)	Energy Received From (Company or Public Authority) [Footnote Affiliations] (b)	Energy Delivered To (Company or Public Authority) [Footnote Affiliations] (c)	Statistic Classification (d)
1	Cooperative Power Association	United Power Association	Various	LF
2	Cooperative Power Association	Western Area Power Administration	Interstate Power	LF
3	Blue Earth L & W	Missouri Basis Mun Pwr Agency	Blue Earth	LF
4	Wisconsin Power & Light	Minnesota Power	Wisconsin Power & Light	*
5	Wisconsin Power & Light	Basin Electric	Wisconsin Power & Light	*
6	Wisconsin Power & Light	Basin Electric	Wisconsin Power & Light	*
7	Wisconsin Power & Light	Minnesota Power	Wisconsin Power & Light	*
8	Wisconsin Power & Light	Wisconsin Power & Light	Blue Earth	*
9	MidAmerican Energy	MidAmerican Energy	St. Joseph Power & Light	LF
10	So MN Municipal Power Agency	Sherco 3 Power Plant	Various	LF
11	City of Mountain Lake	West Area Power Administration	Interstate Power	LF
12	Wis Public Power Inc System-West	Minnesota Power	Various	LF
13	Wis Public Power Inc System-East	Minnesota Power	Various	LF
14	Wisc Public Power Inc System	Otter Tail Pwr Co.	Wisconsin Electric Power	*
15	Wisc Public Power Inc System	Minnesota Power	Wisconsin Electric Power	*
16	Wisc Public Power Inc System	Basin Electric	Wisconsin Electric Power	*
17	Wisc Public Power Inc System	Wisconsin Electric Power	Wis Public Power Inc System-West	*

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

OS - for other transmission service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm transmission service, regardless of the length of the contract. 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.

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.

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 Megawatthours Received (i)	TRANSFER OF ENERGY Megawatthours Delivered (j)	Line No.
342	Various	Various		2,710,195	2,649,262	1
457	* Sioux Fls Intercon	* Luverne Interconn	29			2
464	Missouri Basin Inter	Blue Earth	4	48,588	48,588	3
NSP Tariff Vol 1	Minnesota Power	Wis P & L Interconn		625	610	4
NSP Tariff Vol 1	Otter Tail Pwr/WAPA	Wis P & L Interconn		575,788	573,750	5
NSP Tariff Vol 1	WAPA	Wis P & L Interconn	240	941,244	938,434	6
NSP Tariff Vol 1	Minnesota Power	Wis P & L Interconn	20	105,897	103,302	7
NSP Tariff Vol 1	WPL Interconn	Blue Earth		1,557	1,500	8
351	Neal Power Plant	St Joseph P & L				9
415	Sherco 3	Various		694,438	647,591	10
453	* Sioux Fls Intercon	* Luverne Interconn	1			11
466	Minnesota Power	Wis Pub Pwr Inc	*	271,178	271,178	12
465	Minnesota Power	WEP, WPS, WPL	62	*	*	13
NSP Tariff Vol 1	Otter Tail Power	WEP		1,375	1,342	14
NSP Tariff Vol 1	Minnesota Power	WEP		3,748	3,658	15
NSP Tariff Vol 1	WAPA	WEP		551	538	16
NSP Tariff Vol 1	WEP	WPPI-West		73,973	72,196	17

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)

(Including transactions referred to as "wheeling")

8. Report in column (i) and (j) the total megawatthours received and delivered.
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 ("0") in column(n). Provide a footnote explaining the nature of the nonmonetary settlement, including the amount and type of energy or service rendered.
10. Provide total amounts in column (i) through (n) as the last line. Enter "TOTAL" in column (a) as the last line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered 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.
		* $50,894	$50,894	1
			* 0	2
65,002			65,002	3
	1,220		1,220	4
	1,115,590	* (80,913)	1,034,677	5
1,637,250		* (227,857)	1,409,393	6
354,000			354,000	7
	3,000		3,000	8
		136,035	136,035	9
		* 115,099	115,099	10
2,568			2,568	11
814,731		* 23,040	837,771	12
916,980			916,980	13
	2,176		2,176	14
	5,110		5,110	15
	855		855	16
	93,067		93,067	17

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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

1. Report all transmission of electricity, i. e. wheeling, provided for other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
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:

LF - for long-term firm transmission service. "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 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.

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

Line No.	Payment By (Company or Public Authority) [Footnote Affiliations] (a)	Energy Received From (Company or Public Authority) [Footnote Affiliations] (b)	Energy Delivered To (Company or Public Authority) [Footnote Affiliations] (c)	Statistic Classification (d)
1	Wisc Public Power Inc System	Wis Public Power Inc System-West	WEP/WPS/WPL	*
2	NW Wisconsin Electric Power	NW Wisconsin Electric Power	Dairyland Power Coop	LF
3	University of North Dakota	Western Area Power Administration	University of North Dakota	LF
4	City of Hillsboro	Western Area Power Administration	Hillsboro	LF
5	Wisconsin Public Service	Minnesota Power	Wisconsin Public Service	*
6	Wisconsin Public Service	Dairyland Power Coop.	Wisconsin Electric Power	*
7	City of Ada	Western Area Power Administration	Ada	LF
8	City of East Grand Forks	Western Area Power Administration	East Grand Forks	LF
9	City of Fairfax	Western Area Power Administration	Fairfax	LF
10	City of Marshall	West Area Pwr Adm, Heartland	Marshall	LF
11	City of Melrose	Western Area Power Administration	Melrose	LF
12	City of Olivia	Western Area Power Administration	Olivia	LF
13	City of St James	West Area Pwr Adm, Miss. Basin	St James	LF
14	City of Sauk Centre	West Area Pwr Adm, Miss. Basin	Sauk Centre	LF
15	City of Sleepy Eye	Western Area Power Administration	Sleepy Eye	LF
16	City of Granite Falls	West Area Pwr Adm, Miss. Basin	Granite Falls	LF
17	City of Sioux Falls	Western Area Power Administration	Sioux Falls	LF

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

OS - for other transmission service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm transmission service, regardless of the length of the contract. 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.

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.

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: Megawatthours Received (i)	TRANSFER OF ENERGY: Megawatthours Delivered (j)	Line No.
NSP Tariff Vol 1	WPPI-West	WPL/WPS/WEP		5,177	5,177	1
451	Black Brook Hydro	NSP-DPC Pnt of Intcn		1,935	1,742	2
440	NSP-WAPA Interconnec	University of ND		45,738	44,710	3
414	NSP-WAPA Interconnec	Hillsboro	5	15,221	14,864	4
NSP Tariff Vol 1	MN Power	Wis Public service		1,019	993	5
NSP Tariff Vol 1	DPC	WEP		638	631	6
474	NSP-WAPA Interconnec	Ada	3	14,873	14,524	7
483	NSP-WAPA Interconnec	East Grand Forks		78,365	76,528	8
477	NSP-WAPA Interconnec	Fairfax	2	9,492	9,270	9
403	NSP-WAPA Interconnec	Marshall	*	133,134	130,014	10
482	NSP-Wapa Interconnec	Melrose	6	38,556	37,652	11
388	NSP-WAPA Interconnec	Olivia	5	23,934	23,373	12
412	*	St James	13	35,612	34,777	13
449	*	Sauk Centre	8	25,693	25,091	14
393	NSP-WAPA Interconnec	Sleepy Eye	3	8,836	8,629	15
436	*	Granite Falls				16
484	NSP-WAPA Intercon	Sioux Falls				17

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

8. Report in column (i) and (j) the total megawatthours received and delivered.
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 ("0") in column(n). Provide a footnote explaining the nature of the nonmonetary settlement, including the amount and type of energy or service rendered.
10. Provide total amounts in column (i) through (n) as the last line. Enter "TOTAL" in column (a) as the last line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered 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.
	$10,354		$10,354	1
	6,153		6,153	2
		* 73,404	73,404	3
93,833			93,833	4
	993		993	5
	1,472	* (49,563)	(48,091)	6
40,648		* 1,979	42,627	7
33,704			33,704	8
27,452	582		28,034	9
896,709			896,709	10
89,165	1,966		91,131	11
35,987			35,987	12
185,979	3,756		189,735	13
130,741	2,797		133,538	14
37,512			37,512	15
		* 33,704	33,704	16
		* 41,387	41,387	17

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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

1. Report all transmission of electricity, i. e. wheeling, provided for other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
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:

LF - for long-term firm transmission service. "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 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.

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

Line No.	Payment By (Company or Public Authority) [Footnote Affiliations] (a)	Energy Received From (Company or Public Authority) [Footnote Affiliations] (b)	Energy Delivered To (Company or Public Authority) [Footnote Affiliations] (c)	Statistic Classification (d)
1	SD State Penitentiary	Western Area Power Administration	SD State Penitentiary	LF
2	City of Springfield	Western Area Power Administration	Interstate Power	LF
3	City of Windom	Western Area Power Administration	Interstate Power	LF
4	Missouri Basin Municipal Power Agency	Western Area Power Administration	Interstate Power	LF
5	Sonat Power Marketing	Otter Tail Power	Wisc Public Service	*
6	Sonat Power Marketing	United Power Assoc.	WPS/WEP	*
7	Sonat Power Marketing	Minnesota Power	WPS/WEP/WPL/DPC	*
8	Sonat Power Marketing	Minnesota Power	WEP/WPS	*
9	Sonat Power Marketing	Southern MN Municipal Pwr Agency	WPS/WPL/WEP	*
10	Sonat Power Marketing	Cooperative Power Assoc.	Wisconsin Public Service	*
11	Sonat Power Marketing	Dairyland Power Coop.	Wisconsin Electric Power	*
12	Heartland Energy Services	Basin Electric Power Coop	Wisconsin Electric Power	*
13	Heartland Energy Services	United Power Assoc.	WPS/WEP/WPL	*
14	Heartland Energy Services	Basin Electric Power Coop.	WPS/WPL/WEP	*
15	Heartland Energy Services	Minnesota Power	Wisconsin Electric Power/WPS	*
16	Heartland Energy Services	Manitoba Hydro	WEP/WPL/WPS	*
17	Wisconsin Electric Power Co	Basin Electric Power Coop.	Wisconsin Electric Power	*

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

OS - for other transmission service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm transmission service, regardless of the length of the contract. 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.

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.

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.
				Megatthours Received (i)	Megatthours Delivered (j)	
385	NSP-WAPA Intercon	SD State Pen				1
454	* Sioux Fls Intercon	* Luverne Intercon	1	5,478	5,478	2
455	* Sioux Fls Intercon	* Luverne Intercon	9	34,748	34,748	3
456	* Sioux Fls Intercon	* Luverne Intercon	53	295,628	295,628	4
NSP Tariff Vol 1	Otter Tail Power	Wis Public Service		3,303	3,218	5
NSP Tariff Vol 1	United Pwr Assoc.	WPS/WEP		15,417	15,229	6
NSP Tariff Vol 1	Minnesota Power	WPS/WEP/WPL/DPC		30,063	29,348	7
NSP Tariff Vol 1	Minnesota Power	WEP/WPS	50	28,859	28,185	8
NSP Tariff Vol 1	SMMPA	WPS/WPL/WEP		4,474	4,349	9
NSP Tariff Vol 1	CPA	WPS		409	400	10
NSP Tariff Vol 1	DPC	WEP		278	272	11
NSP Tariff Vol 1	WAPA	Wis Electric Power		4,868	4,751	12
NSP Tariff Vol 1	United Power Assoc.	WPS/WEP/WPL		6,420	6,259	13
NSP Tariff Vol 1	WAPA	WPS		268	263	14
NSP Tariff Vol 1	Minnesota Power	Wis Elec Power/WPS		140	136	15
NSP Tariff Vol 1	Manitoba Hydro	WEP/WPL/WPS		40,213	39,257	16
NSP Tariff Vol 1	WAPA	Wis Elec Power		2,475	2,415	17

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)

(Including transactions referred to as "wheeling")

8. Report in column (i) and (j) the total megawatthours received and delivered.
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 ("0") in column(n). Provide a footnote explaining the nature of the nonmonetary settlement, including the amount and type of energy or service rendered.
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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.
		* $2,604	$2,604	1
11,136		* 964	12,100	2
68,496		* 5,729	74,225	3
416,052			416,052	4
	4,118		4,118	5
	15,580		15,580	6
	45,303		45,303	7
154,300			154,300	8
	5,486		5,486	9
	400		400	10
	544		544	11
	6,201		6,201	12
	9,143		9,143	13
	52[illegible]		526	14
	204		204	15
	67,911		67,911	16
	5,379		5,379	17

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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

1. Report all transmission of electricity, i. e. wheeling, provided for other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
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:

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Line No.	Payment By (Company or Public Authority) [Footnote Affiliations] (a)	Energy Received From (Company or Public Authority) [Footnote Affiliations] (b)	Energy Delivered To (Company or Public Authority) [Footnote Affiliations] (c)	Statistic Classification (d)
1	Wisconsin Electric Power Co	Otter Tail Power	Wisconsin Electric Power	*
2	Wisconsin Electric Power Co	Minnesota Power	Wisconsin Electric Power	*
3	Wisconsin Electric Power Co	Minnesota Power	Wisconsin Electric Power	*
4	Interstate Power Co	Minnesota Power	Interstate Power	*
5	Interstate Power Co	United Power Association	Interstate Power	*
6	Rainbow Energy Marketing Corp.	United Power Association	Wisconsin Public Service	*
7	Rainbow Energy Marketing Corp.	Southern MN Municipal Pwr Agency	WPL/WPS	*
8	Rainbow Energy Marketing Corp.	Basin Electric	WEP/WPL/WPS	*
9	L&G Pwr Marketing Inc.	Wisconsin Power & Light	Southern MN Municipal Pwr Agency	*
10	JPower Inc.	Basin Electric	Wisc Electric Power	*
11	Koch Power Services Inc.	Basin Electric	Wisc Public Service	*
12	Madison Gas & Electric Co.	Dairyland Power Coop.	Wisc Electric Power	*
13	Minnesota Power	Manitoba Hydro	MN Pwr/WPL	*
14	Minnesota Power	Minnesota Power	Wisconsin Power & Light	*
15	Enron Power Marketing Inc.	Basin Electric	WPL/WEP/WI Pub Pwr Inc	*
16	Enron Power Marketing Inc.	Wisconsin Public Service	SMMPA/UPA	*
17	Enron Power Marketing Inc.	Minnesota Power	WEP/WPL	*

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

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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.

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.
				Megatthours Received (i)	Megatthours Delivered (j)	
NSP Tariff Vol 1	Otter Tail Power	Wis Elec Power		4,826	4,708	1
NSP Tariff Vol 1	Minnesota Power	Wis Elec Power		10,448	9,689	2
NSP Tariff Vol 1	Minnesota Power	Wis Elec Power	1	2,497	2,421	3
NSP Tariff Vol 1	Minnesota Power	Interstate Power	54	178,180	173,905	4
NSP Tariff Vol 1	United Power Assoc	Interstate Power	98	291,781	284,778	5
NSP Tariff Vol 1	UPA	WPS		93	91	6
NSP Tariff Vol 1	S. MN Mun Pwr Agency	WPL/WPS		15,827	15,438	7
NSP Tariff Vol 1	WAPA	WEP/WPL/WPS		7,967	7,775	8
NSP Tariff Vol 1	Wisc Pwr & Light	SMMPA		410	400	9
NSP Tariff Vol 1	WAPA	Wisc Elec Pwr		5,975	5,826	10
NSP Tariff Vol 1	WAPA	Wisc Public Serv.		218	214	11
NSP Tariff Vol 1	Dairyland Pwr Coop.	Wisc Elec Pwr		275	268	12
NSP Tariff Vol 1	Manitoba Hydro	MN Pwr/WPL		2,888	2,820	13
NSP Tariff Vol 1	MN Power	WPL		487	475	14
NSP Tariff Vol 1	WAPA	WPL/WEP/WI Pb Pwr In		7,973	7,779	15
NSP Tariff Vol 1	Wisc Public Service	SMMPA/UPA		191	185	16
NSP Tariff Vol 1	Minnesota Power	WEP/WPL		3,349	3,270	17

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

8. Report in column (i) and (j) the total megawatthours received and delivered.
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 ("0") in column(n). Provide a footnote explaining the nature of the nonmonetary settlement, including the amount and type of energy or service rendered.
10. Provide total amounts in column (i) through (n) as the last line. Enter "TOTAL" in column (a) as the last line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered 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.
	$10,934		$10,934	1
	23,010	* (59,140)	(36,130)	2
5,105		* (350,597)	(345,492)	3
477,900			477,900	4
867,300		* (418,883)	448,417	5
	319		319	6
	30,726		30,726	7
	23,700		23,700	8
	600		600	9
	5,826		5,826	10
	428		428	11
	536		536	12
	3,645		3,645	13
	550		550	14
	9,269		9,269	15
	370		370	16
	3,290		3,290	17

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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

1. Report all transmission of electricity, i. e. wheeling, provided for other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
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:

LF - for long-term firm transmission service. "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 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.

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

Line No.	Payment By (Company or Public Authority) [Footnote Affiliations] (a)	Energy Received From (Company or Public Authority) [Footnote Affiliations] (b)	Energy Delivered To (Company or Public Authority) [Footnote Affiliations] (c)	Statistic Classification (d)
1	Enron Power Marketing Inc.	UPA/DPC	Wisconsin Electric Power	*
2	Enron Power Marketing Inc.	Wisconsin Power & Light	United Power Association	*
3	Cenerprise	Wisconsin Electric Power	Southern MN Municipal Pwr Agency	*
4	Cenerprise	WPL/MHEB	Southern MN Municipal Pwr Agency	*
5	Cenerprise	Coop. Pwr Assoc.	Sleepy Eye	*
6	Cenerprise	Minnesota Power	Willmar	*
7	Cenerprise	Minnesota Power	Blue Earth	*
8	United Power Association	Manitoba Hydro	United Power Association	LF
9	Mid-Continent Area Power Pool	MAPP Members	MAPP Members	*
10	Minnesota Municipal Power Agency	WEP/UPA	MMPA's member cities	LF
11	TOTAL			
12				
13				
14				
15				
16				
17				

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

OS - for other transmission service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm transmission service, regardless of the length of the contract. 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.

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.

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.
				Megatthours Received (i)	Megatthours Delivered (j)	
NSP Tariff Vol 1	UPA/DPC	WEP		591	575	1
NSP Tariff Vol 1	Wisc Pwr & Light	UPA		715	693	2
NSP Tariff Vol 1	WEP	SMMPA		3	3	3
NSP Tariff Vol 1	WPL/MHEB	SMMPA		2,665	2,603	4
NSP Tariff Vol 1	Coop. Pwr Assoc.	Sleepy Eye		5,124	5,124	5
NSP Tariff Vol 1	MN Pwr	UPA	20			6
NSP Tariff Vol 1	MN Pwr	Blue Earth		28	28	7
442	Manitoba Hydro	United Pwr Assoc	200			8
MAPP	MAPP Member System	MAPP Member System				9
Tm-1	WEP/UPA	MMPA's Member cities	165			10
				6,882,932	6,738,928	11
						12
						13
						14
						15
						16
						17

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

8. Report in column (i) and (j) the total megawatthours received and delivered.
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 ("0") in column(n). Provide a footnote explaining the nature of the nonmonetary settlement, including the amount and type of energy or service rendered.
10. Provide total amounts in column (i) through (n) as the last line. Enter "TOTAL" in column (a) as the last line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered 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.
	$600		$600	1
	1,386		1,386	2
	3		3	3
	2,608		2,608	4
	7,980		7,980	5
16,177			16,177	6
	56		56	7
8,040,000			8,040,000	8
		* 1,587,456	1,587,456	9
	2,527,214		2,527,214	10
15,418,727	4,062,936	885,342	20,367,005	11
				12
				13
				14
				15
				16
				17

< Page 328 Line 4 Column d >

OS - Interruptible Service

< Page 328 Line 5 Column d >

OS - Interruptible Service

< Page 328 Line 6 Column d >

OS - Reserved Service

< Page 328 Line 7 Column d >

OS - Reserved Service

< Page 328 Line 8 Column d >

OS - Interruptible Service

< Page 328 Line 14 Column d >

OS - Interruptible Service

< Page 328 Line 15 Column d >

OS - Interruptible Service

< Page 328 Line 16 Column d >

OS - Interruptible Service

< Page 328 Line 17 Column d >

OS - Interruptible Service

< Page 328.1 Line 1 Column d >

OS - Interruptible Service

< Page 328.1 Line 5 Column d >

OS - Interruptible Service

< Page 328.1 Line 6 Column d >

OS - Interruptible Service

< Page 328.2 Line 5 Column d >

OS - Interruptible Service

< Page 328.2 Line 6 Column d >

OS - Interruptible Service

< Page 328.2 Line 7 Column d >

OS - Interruptible Service

< Page 328.2 Line 8 Column d >

OS - Reserved Service

< Page 328.2 Line 9 Column d >

OS - Interruptible Service

< Page 328.2 Line 10 Column d >

OS - Interruptible Service

< Page 328.2 Line 11 Column d >

OS - Interruptible Service

< Page 328.2 Line 12 Column d >

OS - Interruptible Service

< Page 328.2 Line 13 Column d >

OS - Interruptible Service

< Page 328.2 Line 14 Column d >

OS - Interruptible Service

< Page 328.2 Line 15 Column d >

OS - Interruptible Service

< Page 328.2 Line 16 Column d >

OS - Interruptible Service

< Page 328.2 Line 17 Column d >

OS - Interruptible Service

< Page 328.3 Line 1 Column d >

OS - Interruptible Service

< Page 328.3 Line 2 Column d >

OS - Interruptible Service

< Page 328.3 Line 3 Column d >

OS - Reserved Service

< Page 328.3 Line 4 Column d >

OS - Reserved Service

< Page 328.3 Line 5 Column d >

OS - Reserved Service

< Page 328.3 Line 6 Column d >

OS - Interruptible Service

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< Page 328.3 Line 13 Column d >

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OS - Interruptible Service

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OS - Interruptible Service

< Page 328.3 Line 16 Column d >

OS - Interruptible Service

< Page 328.3 Line 17 Column d >

OS - Interruptible Service

< Page 328.4 Line 1 Column d >

OS - Interruptible Service

< Page 328.4 Line 2 Column d >

OS - Interruptible Service

< Page 328.4 Line 3 Column d >

OS - Interruptible Service

< Page 328.4 Line 4 Column d >

OS - Interruptible Service

< Page 328.4 Line 5 Column d >

OS - Interruptible Service

< Page 328.4 Line 6 Column d >

OS - Reserved Service

< Page 328.4 Line 7 Column d >

OS - Interruptible Service

< Page 328.4 Line 9 Column d >

OS - Participation Power, Peaking Power, Firm Power, Economy, General Purpose, Scheduled Outage, Schedule M, Operating Reserve, Operational Control, Short-term Power

< Page 329 Line 2 Column f >

NSP-WAPA 345kv

< Page 329 Line 2 Column g >

NSP-IPW 161kv

< Page 329 Line 11 Column f >

NSP-WAPA 345kv

< Page 329 Line 11 Column g >

NSP-IPW 161kv

< Page 329 Line 12 Column h >

53.7mw = 1/96-4/96; 53.6mw = estimated 5/96-12/96

< Page 329 Line 13 Column i >

WPPI Received nets several schedules together.

< Page 329 Line 13 Column j >

Delivered Schedule = 524,285 MWH

< Page 329.1 Line 10 Column h >

57.92mw = 1/96-4/96; 60.08mw = 5/96-12/96

< Page 329.1 Line 13 Column f >

NSP-WAPA interconnection, and Missouri Basin interconnections.

< Page 329.1 Line 14 Column f >

NSP-WAPA interconnection, and Missouri Basin interconnections.

< Page 329.1 Line 16 Column f >

NSP-WAPA interconnection, and Missouri Basin interconnections

< Page 329.2 Line 2 Column f >

NSP-WAPA 345kv

< Page 329.2 Line 2 Column g >

NSP-IPW 161kv

< Page 329.2 Line 3 Column f >

NSP-WAPA 345kv

< Page 329.2 Line 3 Column g >

NSP-IPW 161kv

< Page 329.2 Line 4 Column f >

NSP-WAPA 345kv

< Page 329.2 Line 4 Column g >

NSP-IPW 161kv

< Page 330 Line 1 Column m >

Settlement on the basis of $.018 mills for KWH's delivered to CPA loads from CPA-NSP integrated transmission system, plus $265.20 per month for host control area costs.

< Page 330 Line 2 Column n >

CPA's compensation to NSP is provided under FERC Rate Schedule no. 342.

< Page 330 Line 5 Column m >

Refund for Transmission Tarrif, Docket No. ER91-21-000. (Jan. 1991 - Oct. 1994)

< Page 330 Line 6 Column m >

Refund for Transmission Tariff, Docket No. ER91-21-000. (Jan. 1991 - Oct. 1994)

< Page 330 Line 10 Column m >

Generation Control and Transmission Control-Transmission Agreement with SMMPA 1/96-10/96; Network Integration Transmission Service 11/96-12/96.

< Page 330 Line 12 Column m >

Meter service charge.

< Page 330.1 Line 3 Column m >

Tranformation service @.0007/kwh; transmission service charge.

< Page 330.1 Line 6 Column m >

Refund for Transmission Tariff,

Docket No. ER91-21-000.
(Jan. 1991 - Oct. 1994)

< Page 330.1 Line 7 Column m >

Transmission Service - Red River Coop.

< Page 330.1 Line 16 Column m >

Transmission facilities charge

< Page 330.1 Line 17 Column m >

Transmission facilities charge

< Page 330.2 Line 1 Column m >

Transmission facilities charge

< Page 330.2 Line 2 Column m >

Transmission losses

< Page 330.2 Line 3 Column m >

Transmission losses

< Page 330.3 Line 2 Column m >

Refund for Transmission Tariff,
Docket No. ER91-21-000.
(Jan. 1991 - Oct 1994)

< Page 330.3 Line 3 Column m >

Refund for Transmission Tariff,
Docket No. ER91-21-000.
(Jan. 1991 - Oct. 1994)

< Page 330.3 Line 5 Column m >

Refund for Transmission Tariff,
Docket No. ER91-21-000.
(Jan. 1991 - Oct 1994)

< Page 330.4 Line 9 Column m >

This amount represents transmission service revenues from the Mid-Continent Area Power Pool (MAPP) for use of NSP's transmission system. The members of MAPP include:

Anoka Electric Cooperative	MidAmerican Energy Company
AES Power, Inc.	MidCon Power Services Corp.
Ames Municipal Electric System	Minnesota Municipal Pwr Agency
Basin Electric Power Cooperative	Minnesota Power
Cedar Falls Municipal Utilities	Minnkota Power Coop., Inc.
Cenerprise, Inc.	Missouri Basin Municipal Power
Central Iowa Power Cooperative	Montana-Dakota Utilities Co.
Commonwealth Edison	Municipal Energy Agency of Neb.
ConAgra Energy Services Co.	Muscatine Power and Water
Cooperative Power	Nebraska Public Power District
Corn Belt Power Cooperative	NorAm Energy Services
Cumberland Municipal Utility	North Iowa Municipal Electric
Dairyland Power Cooperative	Northern States Power Co.
Delano Municipal Utility	Northern States Power Co.-Wisc.
ENRON Power Marketing, Inc.	Northwest Iowa Power Coop.
Fremont Department of Utilities	Northwestern Public Service Co.
Glencoe Municipal Electric Plant	Northwestern Wisconsin Elec Co.
Grand Island Electric Department	Omaha Public Power District
Heartland Consumers Power Dist.	Otter Tail Power Company
Heartland Energy Services	Owatonna Public Utilities
Harlan Municipal Utilities	Rainbow Energy Mktg. Corp.
Hastings Utilities	Rochester Public Utilities
Hutchinson Utilities Commission	Saskatchewan Power Corp.
IES Utilities Inc.	Southern MN Municipal Power
Industrial Energy App., Inc.	Tenaska Power Partners
InterCoast Power Marketing Inc.	United Power Association
Interstate Power Company	Utility - 2000 Energy Corp.
Lincoln Electric System	Western Area Power Admin.
Madelia Municipal Light & Power	Wisconsin Public Power, Inc.
Manitoba Hydro	Wisconsin Power & Light Co.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

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

1. Report all transmission, i.e., wheeling, of electricity provided to respondent by other electric utilities, cooperatives, municipalities, or other public authorities during the year.

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.

3. Provide in column (a) subheadings and classify transmission service purchased from other utilities as: "Delivered Power to Wheeler" or "Received Power from Wheeler."

4. Report in columns (b) and (c) the total megawatthours received and delivered by the provider of the transmission service.

5. In columns (d) through (g), report expenses as shown on bills or vouchers rendered to the respondent. In column (d), provide demand charges. In column (e), provide energy charges related to the amount of energy transferred. In column (f), provide 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 (f). Report in column (g) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero ("0") in column (g). Provide a footnote explaining the nature of the nonmonetary settlement, including the amount and type of energy or service rendered.

6. Enter "TOTAL" in column (a) as the last line. Provide a total amount in columns (b) through (g) as the last line. Energy provided by the respondent for the wheeler's transmission losses should be reported on the Electric Energy Account, page 401. If the respondent received power from the wheeler, energy provided to account for losses should be reported on line 19. Transmission By Others Losses, on page 401. Otherwise, losses should be reported on line 27, Total Energy Losses, page 401.

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

Line No.	Name of Company or Public Authority [Footnote Affiliations] (a)	TRANSFER OF ENERGY: Megawatt-hours Received (b)	TRANSFER OF ENERGY: Megawatt-hours Delivered (c)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (d)	Energy Charges ($) (e)	Other Charges ($) (f)	Total Cost of Transmission ($) (g)
1	East River Electric	435,556	431,244	$219,938			$219,938
2	Redwood Electric Coop	2,870	2,870	* 28,077			28,077
3	Stearns Coop Elec Assn	441	437		* 2,951		2,951
4	McLeod Elec Coop	1,594	1,525	* 1,464			1,464
5	Minnkota Power Coop	21,010	20,598		* 21,849		21,849
6	NSP-WAPA-SD State Pen	374,519	363,540	* 1,783,148			1,783,148
7	NW Wis Elec Power	159,800	149,346		* 435,322		435,322
8	Minnesota Power					* 374,776	374,776
9	North Central Power					* 3,860	3,860
10	Otter Tail Power	1,894,215	1,864,700				
11	WAPA-Mallard Logan Line	274,612	270,554				
12	Mid-Cont. Area Pwr Pool					* 999,920	999,920
13	Various					* 3,038,000	3,038,000
14	Total	3,164,617	3,104,814	2,032,627	460,122	4,416,556	6,909,305
15							
16							

< Page 332 Line 2 Column d >

Settled on a basis of $.76/kw plus basic monthly charge $2,130.82

< Page 332 Line 3 Column e >

Settled on a basis of $.001/kwh; plus fixed monthly charge $233.00.

< Page 332 Line 4 Column d >

Settled on a basis of $.39/kw.

< Page 332 Line 5 Column e >

Settled on a basis of $.001/kwh.

< Page 332 Line 6 Column d >

WAPA transmission service @ $14.18/121,000 kw. This number also includes an accrual for a probable change in the capacity factor.

< Page 332 Line 7 Column e >

Transmission Service @ $3.67/KWH January-April; $3.36/KWH May-August; $22,862.00 fixed monthly charge September-December.

< Page 332 Line 8 Column f >

Phase Angle Regulatory Transformer Cost Sharing Agreement.

< Page 332 Line 9 Column f >

NCP transmission services for LCO (Chippewa Reservoir Power).

< Page 332 Line 12 Column f >

This amount represents transmission service charges from the Mid-Continent Area Power Pool (MAPP) for use of MAPP members transmission systems for sales made to non-MAPP members. This charges is related to sales made to the following entities:

Kansas City Power & Light
Madison Gas & Electric
St. Joseph Light & Power
Union Electric Company
Upper Peninsula Power Co.
Wisconsin Electric Power Co.
Wisconsin Power & Light Co.
Manitoba Hydro

< Page 332 Line 13 Column f >

An Accrual for Network Transmission Service Expense to:

Cooperative Power Association
Dairyland Power Association
Southern Minnesota Municipal Power Agency
Central Minnesota Municipal Power Association

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

MISCELLANEOUS GENERAL EXPENSES (Account 930.2)(ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	$565,985
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	132,574
4	Publishing and Distributing Information and Reports to Stockholders; Trustee, Registrar, and Transfer Agent Fees and Expenses, and Other Expenses of Servicing Outstanding Securities of the Respondent	2,557,614
5	Other Expenses (List items of $5,000 or more in this column showing the (1) purpose, (2) recipient and (3) amount of such items. Group amounts of less that $5,000 by classes if the number of items so grouped is shown)	
6	Annual Shareholders Meeting:	
7	Proxy Statement	31,845
8	Company Postage	37,112
9	Security	9,957
10	Brokers Expense	90,300
11	Audio & Video	61,113
12	Facility (Minneapolis Convention Center)	10,784
13	Other Items	30,909
14		
15		
16	Directors Fees and Expenses:	
17		
18	Active Directors:	
19	H Lyman Bretting	28,437
20	David A Christensen	29,642
21	W John Driscoll	28,678
22	Dale L Haakenstad	28,437
23	Allen F Jacobson	27,633
24	Richard M Kovacevich	28,437
25	Douglas W Leatherdale	25,063
26	John E Pearson	29,641
27	G M Pieschel	28,678
28	Margaret R Preska	27,633
29	A Patricia Sampson	28,437
30		
31	Retired Directors:	
32	N Bud Grossman	16,387
33	W G Phillips	16,387
34	D B Reinhart	16,387
35		
36		
37		
38	Other Expenses (1 item)	227
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	$3,888,297

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

1. Report in Section A for the year the amounts for: (a) Depreciation Expense (Account 403); (b) Amortization of Limited-Term Electric Plant (Account 404); and (c) Amortization of Other Electric Plant (Account 405).

2. Report in section B 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 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 subaccounts used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional classifications and showing a 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 servic? 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 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)	Amortization of Limited-Term ElectricPlant(Acc 404) (c)	Amortization of Other Electric Plant(Acc 405) (d)	Total (e)
1	Intangible Plant		$488,294		$488,294
2	Steam Product Plant	60,241,109			60,241,109
3	Nuclear Production Plant	92,337,861			92,337,861
4	Hydraulic Production Plant--Conventional	195,910		38,592	234,502
5	Hydraulic Production Plant--Pumped Storage				
6	Other Production Plant	5,213,794			5,213,794
7	Transmission Plant	17,992,797			17,992,797
8	Distribution Plant	51,410,660			51,410,660
9	General Plant	6,889,699			6,889,699
10	Common Plant--Electric	7,887,766	6,200,016		14,087,782
11	TOTAL	$242,169,596	$6,688,310	$38,592	$248,896,498

B. Basis for Amortization Charges

ACCOUNT 404

The total computer software amortization of $6,200,016 is based on 60 months (1.67%) on an average basis of $30,938,201. New software ha. ..en capitalized and certain old software has been fully amortized.

ACCOUNT 405

The annual $39,592 amortization charge for Mill-Powers is based on a plant balance of $1,235,057 and a life of 32 years, beginning January 1, 1969. This basis for amortization was approved by Mr. A.L. Litke and Staff (FERC) in a letter to C.K. Larson, dated May 23, 1969.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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	291,791		(17.00%)			15.60
13	312	919,378		0			14.30
14	314	226,290		0			12.90
15	315	139,659		0			12.70
16	316	60,172		0			13.50
17	SUBTOTAL	1,637,290					
18							
19							
20							
21	321 *	294,828					12.30
22	321 *	6,603					12.20
23	322 *	553,248					12.60
24	322 *	15,174					12.60
25	323 *	144,245					12.80
26	323 *	15,251					11.70
27	324 *	196,861					11.90
28	324 *	2,661					12.30
29	325 *	135,171					12.30
30	SUBTOTAL	1,364,042					
31							
32							
33							
34	331	442		(10.00%)			4.10
35	332	2,725		(15.00%)			4.10
36	333	1,140		5.00%			4.10
37	334	276		5.00%			4.10
38	335	42		5.00%			4.10
39	SUBTOTAL	4,625					
40							
41							
42							
43	341	8,328		0			15.00
44	342	4,315		0			8.50
45	344	121,125		0.40%			14.80
46	345	7,220		0			9.30
47	346	1,255		0			2.10
48	SUBTOTAL	142,243					
49							
50	*						

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	352	11,010					34.00
13	353	301,247					31.50
14	354	92,824					28.40
15	355	101,949					23.60
16	356	121,758					28.70
17	357	4,847					42.90
18	358	5,080					32.80
19	SUBTOTAL	638,715					
20							
21							
22							
23	361	21,114					34.50
24	362	242,046					30.50
25	364	153,211					21.80
26	365	184,110					24.90
27	366	83,528					30.60
28	367	416,171					23.60
29	368 *	231,181					24.40
30	368 *	263					16.10
31	368 *	12,840					11.70
32	369 *	50,089					21.30
33	369 *	94,976					22.80
34	370	92,027					19.50
35	371 *	1,246					2.70
36	371 *	19,792					2.60
37	371 *	984					3.30
38	373 *	23,821					8.00
39	373 *	16					4.50
40	SUBTOTAL	1,629,415					
41							
42							
43							
44							
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49							
50							

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	390 *	41,761					35.70
13	390	950					32.80
14	391 *	3,945					12.20
15	391	14,277					3.00
16	392 *						0.30
17	392 *						2.90
18	392 *						3.10
19	392 *						12.90
20	393	1,962					5.70
21	394 *	21,791					10.90
22	394 *	173					2.70
23	395	3,759					14.10
24	396 *	2					2.30
25	396 *						4.50
26	396 *	11					2.90
27	397 *	35,518					4.70
28	397 *	928					5.30
29	398	465					9.70
30	SUBTOTAL	125,542					
31	TOTAL	5,541,872					
32							
33							
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DESCRIPTION SECTION C

P337	Line 21 Nuclear - Structures and Improvements
P337	Line 23 Nuclear - Reactor Plant Equipment
P337	Line 22,24,26,28 - Leased
P337.1	Line 29 Line Transformers
P337.1	Line 30 Line Transformers - Trailers
P337.1	Line 31 Line Capacitors
P337.1	Line 32 Overhead Services
P337.1	Line 33 Underground Services
P337.1	Line 35,36,37 Leased Property on Customer's Premises
P337.1	Line 38 Street Lighting and Signal Systems
P337.1	Line 39 Street Lighting Transformers in Reserve
P337.2	Line 12 Structures and Improvements
P337.2	Line 14 Office Furniture and Equipment
P337.2	Line 21 Other Tools and Work Equipment
P337.2	Line 22 Hand Held Meter Reading Devices
P337.2	Line 24 Power Operated Equipment - Mobile (Licensed)
P337.2	Line 26 Power Operated Equipment - Other
P337.2	Line 27 Communication Equipment
P337.2	Line 28 Communication Equipment - Leased to Others

P337.2 Line 16-19, 25:
Separate Provision is charged to clearing accounts monthly, computed as described below in footnote (1)

		Charged to Clearing Accts	Depreciable Plant Base
P337.2	Line 16 Cars	0	762
P337.2	Line 17 Vans and Light Trucks	341,761	5,172
P337.2	Line 18 Licensed Trailers	161,226	2,342
P337.2	Line 19 Heavy Trucks	1,368,420	23,463
P337.2	Line 25 Trenchers, Loaders, Cranes and Other Power Operated Equipment	365,535	4,872
	Total	2,227,942	36,611

FOOTNOTES: Section C

(1) Column (b) Computation:
(Average Jan + Average Feb + ...Average Dec)/12 = Column (b)
Average Month = (Beginning month + end month)/2
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), (e), and (f) do not apply.

Subaccounts 352-390: Changes requested from the MPUC in 1992 were approved in 1993.

Subaccounts 391-398: Changes requested from the MPUC in 1994 were approved in 1994.

(3) P337 Line 21-29(d) - Effective Aug 1, 1981, Nuclear Plant Decommissioning Costs are recovered using an internal and external sinking fund calculation.

(4) P337.1(c),(d),(e) and (f) are not applicable.
P337.2(c),(d),(e) and (f) are not applicable.

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PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) Miscellaneous Amortization (Account 425) -- Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions -- Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430) -- For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) -- Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)		Amount (b)
1	Miscellaneous Amortization (Account 425)		$14,832
2	TOTAL-425		14,832
3			
4			
5	Other Income Deductions (Account 426)		
6			
7	Donations (Subaccount 426.1)	*	5,002,875
8	TOTAL-426.1		5,002,875
9			
10	Life Insurance (Subaccount 426.2)		
11	Wealth-Op - Cash Surrender Value Earnings		(3,221,599)
12	Wealth-Op - Premium Expense		1,445,885
13	Officer Survivor Benefits-Premium Expense		539,137
14	Officer Survivor Benefits-Cash Surrender Value Earn		(1,054,861)
15	TOTAL-426.2		(2,291,438)
16			
17			
18	Penalties (Subaccount 426.3)		2,000
19	TOTAL-426.3		2,000
20			
21			
22			
23	Expenditures for Certain Civic & Political Activity	*	1,155,120
24	TOTAL-426.4		1,155,120
25			
26			
27	Other Deductions (Subaccount 426.5)		
28	Social and Service Club Dues	*	101,393
29	Employee Corporate Expenses		46,955
30	Settlements of Employment Complaints - Accrual Adj.		(65,384)
31	Regulatory Reserve - Accrual Adjustment		(1,219,279)
32	Construction Project Abandonment		(72,680)
33	MN Seed Capital Investment Abandonment		154,667
34	Deferred Comp Costs-Accrd Earnings & Loan Interest		3,716,337
35	Miscellaneous		64,856
36	TOTAL-426.5		2,726,865
37			
38			
39	Interest on Debt to Associated Companies (Acct 430)		0
40			
41	TOTAL-430		0

PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) Miscellaneous Amortization (Account 425) -- Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions -- Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430) -- For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) -- Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	Other Interest Expense (Account 431)	
2	Commercial Paper	14,522,048
3	Customer Deposits	57,904
4	Coal Mine Reclamation	241,115
5	Manitoba Hydro Interest	283,661
6	Working Capital Fees Charged to Subsidiaries	(168,981)
7	Deferred Compensation Plan - Cost of Capital	486,393
8	Wholesale Refund for Transmission Tariff Interest	255,671
9	Low Income Discount Program	482,846
10	Miscellaneous	86,707
11	TOTAL-431	16,247,364
12		
13		
14		
15		
16		
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39		
40		
41		

< Page 340 Line 7 Column b >

Analysis of Donations - Subaccount 426.1

Arts and Culture	441,556
Building Human Capacity	1,506,320
Education	585,767
Community Development	1,704,860
Regional Grants	512,112
Miscellaneous	252,260

TOTAL	5,002,875
	=========

< Page 340 Line 23 Column b >

Expenditures for Certain Civic, Political and Related Activities
(Account 426.4)

Salaries & Expenses while lobbying MN State Agencies	529,678
Salaries & Expenses while lobbying Federal Agencies	229,582
Edison Electric Institute	59,889
MN Utilities Investors Group	218,973
DLC Board Membership	10,000
Minnesota WINS Support	100,000
Various Miscellaneous Items	6,998

TOTAL	1,155,120
	=========

< Page 340 Line 28 Column b >

Analysis of Social and Service Club Dues
(See Other Deductions-Subaccount 426.5 on Page 340)

Edina Country Club	6,029
Fargo Country Club	7,530
Grand Forks Country Club	1,550
Lions Club	2,144
Midland Hills Country Club	3,072
Minikahda Club	4,515
Minneapolis Athletic Club	13,939
Minneapolis Club	16,216
Minnesota Club	10,195
Minot Country Club	1,500
Rotary Club	15,581
St. Cloud Rotary Club	2,746
Westward Ho Country Club	3,260
Winona Country Club	2,327
Sixteen miscellaneous other clubs	10,789

TOTAL	101,393
	=======

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 formal 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 Expenses 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 Docket Numbers				
5	E-002/RP-95-589 (1995 Resource Plan)		113,702	113,702	
6					
7					
8					
9					
10	Assessments by the State of Minnesota,				
11	Minnesota Public Service Commission and the				
12	Department of Public Service for rate and				
13	other expenses in accordance with provision	1,694,387		1,694,387	
14	of the 1974 utility regulation law	365,698		365,698	
15					
16					
17					
18					
19	State of South Dakota Public Utilities				
20	Commission special hearing fund assessment	113,774		113,774	
21					
22					
23					
24					
25	State of Wisconsin (share licensing fees)		500,661	500,661	
26					
27					
28					
29	Expenses incurred preparing filing and				
30	attending conferences and hearings in				
31	connection with various FERC electric rate				
32	filings				
33	ER94-1090 & ER94-1113		84,229	84,229	
34	Order 888 (RM95-8 & RM94-7)		35,592	35,592	
35	FERC Annual Assessment	1,083,988		1,083,988	
36					
37					
38					
39					
40	Various Miscellaneous Regulatory Expenses				
41	Electric		201,100	201,100	
42	Gas		16,071	16,071	
43					
44					
45					
46	TOTAL	$3,257,847	$951,355	$4,209,202	0

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			
CHARGED CURRENTLY TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3, End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
							2
							3
							4
Electric	E928	113,702					5
							6
							7
							8
							9
							10
							11
							12
Electric	E928	1,694,387					13
Gas	G928	365,698					14
							15
							16
							17
							18
							19
Electric	E928	113,774					20
							21
							22
							23
							24
Electric	E928	500,661					25
							26
							27
							28
							29
							30
							31
							32
Electric	E928	84,229					33
Electric	E928	35,592					34
Electric	E928	1,083,988					35
							36
							37
							38
							39
							40
Electric	E928	201,100					41
Gas	G928	16,071					42
							43
							44
							45
[redacted]		$4,209,202	0	[redacted]	0	0	46

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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, developmen., and demonstration in Uniform System of Accounts.)

2. Indicate in column (a) the applicable classification, as shown below. Classifications:

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

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

Line No.	Classification (a)	Description (b)
1	(A) Electric RD&D Performed Internally	
2	(1) Generation	
3	A Hydropower	
4	None	
5	B Fossil Fuel - Steam	
6	Black Dog #2 FBC Optimization	
7	Life Assessmnt & Ext High Temp Pres Prts	
8	Simulator and Training Program	
9	In-Situ Clip Replacement	
10	Computer Based Training	
11	Wet ESP	
12	Cyclone Nox Control Interest Group	
13	C Internal Combustion or Gas Turbine	
14	Variable cost of Providing Spinning Rsv	
15	D Nuclear	
16	Fatigue Pro Upgrade	
17	PLC Applications	
18	Sleeved Tube Examination	
19	Steam Generator Strategic Management	
20	Depleted Zinc Oxide	
21	BWR Vessel and Internals	
22	Enhancement to Gothic Code	
23	Programmable Project Controls	
24	E Unconventional Generation	
25	Fuel Cell Demonstration	
26	F Siting & Heat Rejection	
27	None	
28	(2) System Planning Engineering & Operation	
29	None	
30	(3) Transmission	
31	A Overhead	
32	Power Transf Static Electrification Risk	
33	B Underground	
34	Cable Partial Discharge Location	
35	(4) Distribution	
36	Nova-Distribution Automation	
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 $5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A.(6) and B.(4)) classify items by type of R, D & D activity.

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

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

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
					4
					5
476		930.2	476		6
21		930.2	21		7
150,000		930.2	150,000		8
9,000		930.2	9,000		9
10,000		930.2	10,000		10
300,000		930.2	300,000		11
10,000		930.2	10,000		12
					13
10,000		930.2	10,000		14
					15
30,000		930.2	30,000		16
50,000		930.2	50,000		17
50,000		930.2	50,000		18
15,000		930.2	15,000		19
44,000		930.2	[illegible],000		20
100,000		930.2	100,000		21
5,000		930.2	5,000		22
15,000		930.2	15,000		23
					24
17		930.2	17		25
					26
					27
					28
					29
					30
					31
20,000		930.2	20,000		32
					33
6,000		930.2	6,000		34
					35
164		930.2	164		36
					37
					38

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

2. Indicate in column (a) the applicable classification, as shown below. Classifications:

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

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

Line No.	Classification (a)	Description (b)
1	(A) Electric RD&D Performed Internally (Cont.)	
2		
3	(5) Environment-Other Than Equipment	
4	None	
5	(6) Other	
6	A Alternative Energy	
7	Photovoltaics	
8	B By-Product Utilization	
9	None	
10	C Conservation	
11	None	
12	D Load Management	
13	Non-Road Electric Vehicles	
14	Electric Vehicle Demonstration	
15	E Load Research	
16	None	
17	F Metering	
18	Jurisdictional Metering	
19	G Research-General	
20	Center for Hardy Landscape Plants	
21	Induction Forming Process	
22	Predicting Customer Choice	
23	FP Ind Wastewater Recovery Membrane	
24	Lightning and Severe Weather	
25	Electrotechnologies for Small Business	
26	Food Processing Center	
27	Geothermal Heat Pump Consortium	
28	Pollution Prevention	
29	Waste Accounting	
30	Geothermal Heat Pumps	
31	Custom Power #94008	
32		
33		
34	(B) Electric RD&D Performed Externally	
35	(1) Research Support to EPRI	
36	EPRI Membership	
37	a. Generation-Nuclear	
38	b. Generation-Other	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute

(3) Research Support to Nuclear Power Groups

(4) Research Support to Others (Classify)

(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A.(6) and B.(4)) classify items by type of R, D & D activity.

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

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

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
					4
					5
					6
356,184		930.2	356,184		7
					8
					9
					10
					11
					12
10,000		930.2	10,000		13
2,468		930.2	2,468		14
					15
					16
					17
1,227		930.2	1,227		18
					19
4,639		930.2	4,639		20
14,000		930.2	14,000		21
50,000		930.2	50,000		22
22,500		930.2	22,500		23
9,000		930.2	9,000		24
25,000		930.2	25,000		25
65,000		930.2	65,000		26
59,000		930.2	59,000		27
20,000		930.2	20,000		28
20,000		930.2	20,000		29
16,000		930.2	16,000		30
2,550		930.2	2,550		31
					32
					33
					34
					35
					36
	3,382,356	524	3,382,356		37
	1,259,125	506	1,259,125		38

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

2. Indicate in column (a) the applicable classification, as shown below. Classifications:

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

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

Line No.	Classification (a)	Description (b)
1	c. Transmission	
2	EPRI Advisory Group Participation	
3	Research - EPRI	
4	(2) Research Support to Edision Elec Inst.	
5	None	
6	(3) Research Support to Nuclear Power Groups	
7	None	
8	(4) Research Support to Others	
9	National Lighting Product Info Program	
10		
11	TOTAL	
12		
13		
14		
15		
16		
17		
18		
19		
20		
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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A.(6) and B.(4)) classify items by type of R, D & D activity.

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

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

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amount (f)	Unamortized Accumulation (g)	Line No.
	$1,100,084	566	$1,100,084		1
	7,756	930.2	7,756		2
	109,041	930.2	109,041		3
					4
					5
					6
					7
					8
	50,000	930.2	50,000		9
					10
1,502,246	5,908,362		7,410,608	0	11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
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					36
					37
					38

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	$84,611,458		
4	Transmission	3,845,606		
5	Distribution	19,551,831		
6	Customer Accounts	17,753,849		
7	Customer Service and Informational	6,580,557		
8	Sales	806,794		
9	Administrative and General	46,169,647		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	$179,319,742		
11	Maintenance			
12	Production	39,465,844		
13	Transmission	2,470,072		
14	Distribution	10,124,302		
15	Administrative and General	1,954		
16	TOTAL Maint. (Total of lines 12 thru 15)	$52,062,172		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	$124,077,302		
19	Transmission (Enter Total of lines 4 and 13)	$6,315,678		
20	Distribution (Enter Total of lines 5 and 14)	$29,676,133		
21	Customer Accounts (Transcribe from line 6)	17,753,849		
22	Customer Service and Informational(Transcribe from line 7)	6,580,557		
23	Sales (Transcribe from line 8)	806,794		
24	Administrative and General (Enter Total of lines 9 and 15)	$46,171,601		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	$231,381,914	$2,785,315	$234,167,229
26	Gas			
27	Operation			
28	Production--Manufactured Gas	239,288		
29	Production--Nat. Gas(Including Expl. and Dev.)	0		
30	Other Gas Supply	500,352		
31	Storage, LNG Terminaling and Processing	625,336		
32	Transmission	658,052		
33	Distribution	8,674,990		
34	Customer Accounts	3,977,526		
35	Customer Service and Informational	1,167,815		
36	Sales	558,154		
37	Administrative and General	6,286,187		
38	TOTAL Operation (Enter Total of lines 28 thru 37)	$22,687,700		
39	Maintenance			
40	Production--Manufactured Gas	158,848		
41	Production--Natural Gas	0		
42	Other Gas Supply	6,534		
43	Storage, LNG Terminaling and Processing	307,513		
44	Transmission	76,938		
45	Distribution	4,608,326		
46	Administrative and General	24,458		
47	TOTAL Maint. (Enter Total of lines 40 thru 46)	$5,182,617		

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
	Gas			
48	Total Operation and Maintenance			
49	Production--Manufactured Gas (Enter Total of lines 28 and 40)	$398,136		
50	Production--Natural Gas (Including Expl. and Dev.) (Total of lines 29 and 41)	0		
51	Other Gas Supply (Enter Total of lines 30 and 42)	$506,886		
52	Storage, LNG Terminaling and Processing (Total of lines 31 and 43)	$932,849		
53	Transmission (Lines 32 and 44)	$734,990		
54	Distribution (Lines 33 and 45)	$13,283,316		
55	Customer Accounts (Line 34)	3,977,526		
56	Customer Service and Informational (Line 35)	1,167,815		
57	Sales (Line 36)	558,154		
58	Administrative and General (Lines 37 and 46)	$6,310,645		
59	TOTAL Operation and Maint. (Total of lines 49 thru 58)	$27,870,317	$539,438	$28,409,755
60	Other Utility Departments			
61	Operation and Maintenance			0
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	$259,252,231	$3,324,753	$262,576,984
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	50,182,514	3,585,069	53,767,583
66	Gas Plant	5,000,151	242,236	5,242,387
67	Other			
68	TOTAL Construction (Total of lines 65 thru 67)	$55,182,665	$3,827,305	$59,009,970
69	Plant Removal (By Utility Departments)			
70	Electric Plant	5,460,640	215,002	5,675,642
71	Gas Plant	1,391,961	17,865	1,409,826
72	Other	0	0	0
73	TOTAL Plant Removal (Total of lines 70 thru 72)	$6,852,601	$232,867	$7,085,468
74	Other Accounts (Specify):			
75	Non Operating & Non Utility Income Accounts	3,832,467	65,820	3,898,287
76	Accounts Receivable	4,831,806	179,692	5,011,498
77	Materials & Supplies	6,113,164	832,226	6,945,390
78	Prepaids	1,664		1,664
79	Temporary Facilities	229,369	6,029	235,398
80	Other Deferred Debits	7,517,633	579,716	8,097,349
81	Conservation Programs	3,586,417		3,586,417
82	Hazardous Waste Disposal	337,311		337,311
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	$26,449,831	$1,663,483	$28,113,314
96	TOTAL SALARIES AND WAGES	$347,737,328	$9,048,408	$356,785,736

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.

2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.

3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.

4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

1,2,3 - See below

COMMON UTILITY PLANT IN SERVICE ACCOUNT	COST AT 31-Dec-96	ALLOCATED TO UTILITY DEPARTMENTS Electric	 Gas
INTANGIBLE PLANT			
301 Organization	$100,608	$93,344	$7,264
303 Computer Software	68,270,615	60,748,054	7,522,561
Total Intangible Plant	$68,371,223	$60,841,398	$7,529,825
GENERAL PLANT			
389 Land and Land Rights	$1,922,351	$1,399,016	$523,335
390 Structures and Improv.	44,680,672	35,550,713	9,129,959
391 Office furn. and equip.	86,328,749	76,453,993	9,874,756
392 Transportation equip.	297,519	197,743	99,776
393 Stores equipment	942,196	539,969	402,227
394 Tools/shop/garage equip	4,017,124	2,855,175	1,161,949
395 Laboratory equipment	35,983	32,839	3,144
396 Power operated equip.	11,414	7,521	3,893
397 Communication equip.	21,672,871	16,791,110	4,881,761
398 Miscellaneous equip.	782,811	673,656	109,155
Total General Plant	$160,691,690	$134,501,735	$26,189,955
Total Common Util Plant-In Service	$229,062,913	$195,343,133	$33,719,780

COMMON UTILITY PLANT COMPLETED CONSTRUCTION NOT CLASSIFIED			
General Plant	$0	$0	$0
COMMON UTILITY PLANT HELD FOR FUTURE USE			
General Plant			
389 Land and Land Rights	$3,961,053	$3,679,026	$282,027
COMMON UTILITY PLANT CONSTRUCTION WORK IN PROGRESS			
General Plant	$31,155,693	$28,399,893	$2,755,800
COMMON UTILITY PLANT ACCUMULATED PROVISION FOR DEPRECIATION			
General Plant	$90,778,974	$79,258,987	$11,519,987

METHOD OF ALLOCATION

The above items of Common Utility Plant and Accumulated Provision for Depreciation have been allocated to various utilities on the basis of customers and employee labor.

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.

2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.

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4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

COMMON UTILITY PLANT EXPENSES

Account	TOTAL	ALLOCATED TO UTILITY DEPARTMENTS Electric	Gas
CUSTOMER ACCOUNTS EXPENSES			
902 Meter reading expenses	5	4	1
903 Customer records & collection exp	$35,709	$30,056	$5,653
905 Misc customer accounts expense	66	56	10
Total Customer Accounts Expenses	$35,780	$30,116	$5,664
CUSTOMER SERVICE AND INFORMATIONAL EXPENSES			
909 Inform & instruct advertising exp	$110,262	$92,804	$17,458
910 Misc cust service and info exp	899	757	142
Total Customer Serv & Info Exp	$111,161	$93,561	$17,600
ADMINISTRATIVE AND GENERAL EXPENSES			
920 Admin and general salaries	$26,110,061	$23,537,508	$2,572,553
921 Office supplies and expenses	17,021,579	15,482,927	1,538,652
922 Admin expenses transferred	(4,396,067)	(4,046,168)	(349,899)
923 Outside services employed	1,941,128	1,725,733	215,395
924 Property insurance	239,904	176,303	63,601
925 Injuries and damages	1,704,783	1,471,210	233,573
926 Employee pensions and benefits	10,286,297	9,352,705	933,592
930.1 Miscellaneous general expenses	94,917	86,210	8,707
930.2 Miscellaneous general expenses	2,204,148	2,003,925	200,223
931 Rents	2,163,811	1,909,576	254,235
935 Maintenance of general plant	1,703	1,475	228
Total Admin & General Expenses	$57,372,264	$51,701,404	$5,670,860
403 Depreciation Expense	$9,538,054	$7,887,766	$1,650,288
404 Amort of limited term common plnt	6,903,714	6,200,016	703,698
408 Taxes other than income taxes	2,033,213	1,846,447	186,766
Total Common Utility Plant Expenses	$75,994,186	$67,759,310	$8,234,876

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of su.. ..ant costs to the respective departments using the common u..lity plant and explain the basis of allocation used, giving the allocation factors.

2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.

3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.

4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Basis of Allocation of Common Utility Plant Expenses

Accounts	
902,903,909	Number of customers bills of the various utilities to average total customers at year-end 1995.
920 to 935 Incl. 408	Administrative and General expenses and tax other than income taxes were allocated based on the 1996 Labor allocator.
403,404	Common Depreciation Expense has been allocated to various utilities on the basis of studies that consider customers, labor, and services received.
	Pension costs on labor affecting operating accounts were charged to account 926.

4 - The use of common utility plant classification was recommended by commission letter dated 8-14-69.

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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	20,186,111
4	Nuclear	12,096,022
5	Hydro--Conventional	80,217
6	Hydro--Pumped Storage	0
7	Other	54,593
8	(Less) Energy for Pumping	0
9	Net Generation (Enter Total of lines 3 thru 8)	32,416,943
10	Purchases	9,246,297
11	Power Exchanges:	
12	Received	209,474
13	Delivered	38,803
14	Net Exchanges (Line 12 minus line 13)	170,671
15	Transmission For Other (Wheeling)	
16	Received	6,882,932
17	Delivered	6,738,928
18	Net Transmission for Other (Line 16 minus Line 17)	144,004
19	Transmission By Other Losses	(59,803)
20	TOTAL (Enter Total of Lines 9, 10,14,18 and 19)	41,918,112

Line No.	Item (a)	Megawatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	29,721,550
23	Requirements Sales for Resale (See instruction 4, page 311.)	5,623,442
24	Non-Requirements Sales For Resale (See Instruction 4, page 311.)	4,163,859
25	Energy Furnished Without Charge	1,374
26	Energy Used by the Company (Electric Department Only, Excluding Station Use)	* 47,194
27	Total Energy Losses	2,360,693
28	TOTAL(Enter Total of Lines 22 Thru 27) (MUST EQUAL LINE 20)	41,918,112

MONTHLY PEAKS AND OUTPUT

1. 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 in column (b) the system's energy output for each month such that the total on line 41 matches the total on line 20.
3. Report in column (c) a monthly breakdown of the Non-Requirements Sales For Resale reported on line 24. Include in the monthly amounts any energy losses associated with the sales so that the total on line 41 exceeds the amount on line 24 by the amount of losses incurred (or estimated) in making the Non-Requirements Sales For Resale.
4. Report in column (d) the system's monthly maximum megawatt load (60-minute integration) associated with the net energy for the system defined as the difference between columns (b) and (c).
5. Report in columns(e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: * Northern States Power Company (Minnesota)

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales For Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	3,371,558	260,374	4,482	30	19
30	February	3,077,737	230,657	4,538	1	19
31	March	3,167,970	214,329	4,248	7	20
32	April	2,958,990	348,491	3,994	3	11
33	May	3,002,586	340,942	4,191	17	14
34	June	3,426,450	323,263	6,066	28	15
35	July	3,537,368	341,031	5,819	18	16
36	August	3,761,700	361,097	6,178	6	16
37	September	3,216,141	316,362	5,825	4	17
38	October	3,375,573	524,412	4,189	30	18
39	November	3,300,677	454,055	4,366	26	18
40	December	3,554,481	448,846	4,523	18	18
41	TOTAL	39,751,231	* 4,163,859			

< Page 401 >

1) Certain parts of the sys em of the respondent are connected or interconnected with the systems of parts of the systems of the Northern States Power Company (Wisconsin), which is a subsidiary of Northern States Power Company (Minnesota).

2) Sales to other utilities at time of the Interconnected System monthly peaks and not included in column (d)

Month	MW Sales to Other Utilities
January	320
February	145
March	320
April	381
May	501
June	36
July	7
August	207
September	195
October	1149
November	297
December	464

3) Non-integrated systems

NAME OF SYSTEM: Fargo-Grand Forks North Dakota System

Month	Total Monthly Energy	Month Non-req Sales For Resale & Associated Losses	Monthly Peak Megawatt	Day/Month	Hour
(a)	(b)	(c)	(d)	(e)	(f)
Jan	202,016		352	30	8
Feb	173,418		359	1	8
Mar	175,179		335	6	8
Apr	142,478		260	1	8
May	128,215		238	9	9
Jun	134,040		289	11	16
Jul	135,016		270	16	17
Aug	145,435		279	29	18
Sep	127,982		307	5	17
Oct	140,898		279	30	19
Nov	168,683		320	26	8
Dec	191,340		332	18	18
Total	1,864,700				

NAME OF SYSTEM: Minot North Dakota System

Jan	28,619		52	30	19
Feb	25,027		54	1	19
Mar	25,541		47	6	20
Apr	22,486		42	1	12
May	21,839		40	9	12
Jun	24,121		59	11	17
Jul	25,846		57	16	14
Aug	27,498		61	28	17
Sep	22,688		49	9	17
Oct	23,925		47	30	19
Nov	25,587		49	25	19
Dec	29,004		52	16	18
Total	302,1[illegible]				

< Page 401 Line 26 Column b >

Includes 17,821 MWH sales to NRG Energy, Inc., a wholly owned subsidiary of the Company, pursuant to a contract between the Company and NRG as approved by the Minnesota Public Utilities Commission.

< Page 401 Column c >

Regarding column (c), Non-Requirements Sales for Resale and Associated Losses, Northern States Power does not supply losses for any particular sale. Rather, the value of the energy to supply the sale is reflected in the price. Consequently, NSP has no separate accounting for losses due to sales.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

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 on this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis, report the Btu content of the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (line 37) and average cost per unit of fuel burned (line 40) must be consistent with charges to expense accounts 501 and 547 (line 41) as show on line 19.
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: Black Dog (b)			Plant Name: MN Valley (c)		
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)	Steam			Steam		
2	Type of Plant Construction(Conventional, Outdoor Boiler, Full Outdoor, Etc.)	Conventional			Conventional		
3	Year Originally Constructed	1952			1932		
4	Year Last Unit was Installed	1960			1953		
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	512.00			46.00		
6	Net Peak Demand on Plant -- MW (60 minutes)	351			47		
7	Plant Hours Connected to Load	7,873			384		
8	Net Continuous Plant Capability (Megawatts)						
9	When Not Limited by Condenser Water	434			47		
10	When Limited by Condenser Water	461			47		
11	Average Number of Employees	92			8		
12	Net Generation,Exclusive of Plant Use --KWh	1,235,319,000			10,000,000		
13	Cost of Plant: Land and Land Rights	952,692			20,492		
14	Structures and Improvements	23,950,742			3,746,175		
15	Equipment Costs	161,216,376			9,464,827		
16	Total Cost	$186,119,810			$13,231,494		
17	Cost per KW of Installed Capacity (line 5)	363.5152			287.6411		
18	Production Expenses: Oper. Supv. & Engr.	870,772			105,293		
19	Fuel	15,691,482			146,691		
20	Coolants and Water (Nuclear Plants Only)						
21	Steam Expenses	1,774,381			54,580		
22	Steam From Other Sources						
23	Steam Transferred (Cr.)						
24	Electric Expenses	794,185			170,560		
25	Misc. Steam (or Nuclear) Power Expenses	1,756,144			267,224		
26	Rents	34,264			72		
27	Allowances						
28	Maintenance Supervision and Engineering	942,917			57,892		
29	Maintenance of Structures	383,334			71,855		
30	Maintenance of Boiler (Or Reactor) Plant	2,767,008			44,327		
31	Maintenance of Electric Plant	3,590,524			23,699		
32	Maintenance Misc. Steam (or Nuclear) Plant	533,750			22,973		
33	Total Production Expenses	$29,138,761			$965,166		
34	Expenses per Net KWh	$0.0235			$0.0965		
35	Fuel: Kind (Coal,Gas,Oil,or Nuclear)	Coal	Gas	Oil	Coal	Gas	Oil
36	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-Mcf)(Nuclear-indicate)	Tons	MCF	Bbls	Tons	MCF	Bbls
37	Quantity (Units) of Fuel Burned	780,585	135,739	36	5,033	12,748	160
38	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if nuclear)	8,789	1,017	141,354	9,142	1,015	141,691
39	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year	$18.170	$2.700	$24.460	$18.420	$2.310	$23.180
40	Average Cost of Fuel per Unit Burned	$19.620	$2.750	$28.520	$22.390	$2.370	$23.920
41	Avg. Cost of Fuel Burned per Million Btu	$1.120	$2.710	$4.770	$1.220	$2.330	$4.010
42	Avg. Cost of Fuel Burned per KWh Net Gen		* $12.700			* $14.670	
43	Average Btu per KWh Net Generation		* 11.220			* 10.590	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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. 548 and 549 on line 24 "Electric Expenses," and Maintenance Account Nos.553 and 554 on line 31 "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: Wilmarth (d)			Plant Name: High Bridge (e)			Plant Name: Riverside (f)			Line No.
Steam			Steam			Steam			1
Conventional			Conventional			Conventional			2
1948			1924			1911			3
1951			1959			1964			4
25.00			276.84			403.85			5
11			93			357			6
8,230			6,623			8,232			7
									8
22			263			362			9
22			262			357			10
25			113			122			11
103,620,000			1,067,393,000			1,913,892,000			12
$368,322			$528,150			$397,485			13
4,649,732			19,789,801			27,143,677			14
29,726,339			66,165,703			137,627,779			15
$34,744,393			$86,483,654			$165,168,941			16
1,389.7757			312.3958			408.9858			17
153,091			842,640			882,018			18
1,472,765			12,755,182			20,936,824			19
									20
715,946			2,035,083			3,889,737			21
									22
									23
387,208			382,904			232,467			24
521,062			2,059,075			2,066,058			25
627			33,739			20,973			26
									27
250,332			637,112			760,166			28
82,742			354,859			441,139			29
1,618,378			1,933,355			2,975,888			30
497,458			196,252			729,339			31
218,169			418,761			337,990			32
$5,917,778			$21,648,962			$33,272,599			33
$0.0571			$0.0202			$0.0173			34
RDF	Gas		Coal	Gas	Oil	Coal	Gas	Oil	35
Tons	MCF		Tons	MCF	Bbls	Tons	MCF	Bbls	36
160,959	15,658		670,634	148,363	517	1,141,913	37,400	3,506	37
5,782	1,018		8,809	1,018	139,584	9,055	1,016	140,184	38
$4.710	$3.780		$17.370	$2.360	$18.180	$16.650	$3.080	$22.710	39
$8.770	$3.930		$18.470	$2.430	$19.490	$18.160	$3.120	$23.740	40
$0.760	$3.860		$1.050	$2.380	$3.330	$1.000	$3.070	$4.030	41
	* $14.210			* $11.950			* $10.940		42
	* 18.120			* 11.210			* 10.840		43

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

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 on this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content of the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (line 37) and average cost per unit of fuel burned (line 40) must be consistent with charges to expense accounts 501 and 547 (line 41) as show on line 19.
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: West Faribault (b)	Plant Name: Pathfinder (c)
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)	Gas Turbine	Steam
2	Type of Plant Construction(Conventional, Outdoor Boiler, Full Outdoor, Etc.)	Ind Enclosures	Conventional
3	Year Originally Constructed	1965	1969
4	Year Last Unit was Installed	1965	1969
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	32.30	75.00
6	Net Peak Demand on Plant -- MW (60 minutes)	32	61
7	Plant Hours Connected to Load	31	27
8	Net Continuous Plant Capability (Megawatts)	32	
9	When Not Limited by Condenser Water		64
10	When Limited by Condenser Water		61
11	Average Number of Employees	0	8
12	Net Generation,Exclusive of Plant Use --KWh	785,000	(689,000)
13	Cost of Plant: Land and Land Rights	19,415	289,140
14	Structures and Improvements	117,231	3,535,234
15	Equipment Costs	3,637,272	11,930,671
16	Total Cost	$3,773,918	$15,755,045
17	Cost per KW of Installed Capacity (line 5)	116.8395	210.0672
18	Production Expenses: Oper. Supv. & Engr.	8,674	52,584
19	Fuel	37,962	52,647
20	Coolants and Water (Nuclear Plants Only)		
21	Steam Expenses		14,824
22	Steam From Other Sources		
23	Steam Transferred (Cr.)		
24	Electric Expenses	815	57,075
25	Misc. Steam (or Nuclear) Power Expenses	12,814	275,818
26	Rents	6,738	
27	Allowances		
28	Maintenance Supervision and Engineering	12,340	34,294
29	Maintenance of Structures	14	24,504
30	Maintenance of Boiler (Or Reactor) Plant		30,147
31	Maintenance of Electric Plant	33,083	14,575
32	Maintenance Misc. Steam (or Nuclear) Plant		55,500
33	Total Production Expenses	$112,440	$611,968
34	Expenses per Net KWh	$0.1432	($0.8881)
35	Fuel: Kind (Coal,Gas,Oil,or Nuclear)	Gas	Gas
36	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-Mcf)(Nuclear-indicate)	MCF	MCF
37	Quantity (Units) of Fuel Burned	18,281	18,331
38	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if nuclear)	1,010	1,016
39	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year	$2.080	$2.750
40	Average Cost of Fuel per Unit Burned	$2.080	$2.870
41	Avg. Cost of Fuel Burned per Million Btu	$2.060	$2.830
42	Avg. Cost of Fuel Burned per KWh Net Gen	$48.360	* ($76.410)
43	Average Btu per KWh Net Generation	23.510	* (27.030)

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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. 548 and 549 on line 24 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on line 31 "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: A S King (d)	Plant Name: * Sherburne County (e)	Plant Name: Blue Lake (f)	Line No.
Steam	Steam	Gas Turbine	1
Conventional	Conventional	Ind Enclosures	2
1968	1976	1974	3
1968	1987	1974	4
598.40	2,129.00	226.80	5
567	1,823	194	6
7,590	8,784	50	7
		190	8
581	2,295		9
567	2,295		10
99	429	4	11
3,420,529,000	12,312,723,000	9,813,000	12
$666,505	$5,744,745	$190,122	13
21,812,601	183,911,273	965,267	14
106,051,240	807,920,571	19,830,219	15
$128,530,346	$997,576,589	$20,985,608	16
214.7900	468.5658	92.5291	17
756,448	4,273,768	45,441	18
34,777,792	143,584,906	742,187	19
			20
2,104,011	5,334,184		21
			22
			23
582,934	1,348,931	80,790	24
3,084,663	9,266,805	153,998	25
34,030	27,738	125	26
			27
769,361	1,527,738	23,518	28
384,056	1,243,830	7,459	29
3,362,671	7,957,546		30
479,037	1,751,699	174,056	31
458,526	1,197,428	36,996	32
$46,793,529	$177,514,573	$1,264,570	33
$0.0136	$0.0144	$0.1288	34

(d)			(e)			(f)			Line No.
Coal	Gas	Wood	Coal		Oil			Oil	35
Tons	MCF	Tons	Tons		Bbls			Bbls	36
1,800,426	9,220	15,859	7,293,920		14,538			32,828	37
9,289	1,018	6,729	8,684		139,838			138,001	38
$17.990	$2.500	$16.790	$19.000		$23.540			$22.610	39
$19.150	$2.620	$16.910	$19.640		$25.090			$22.610	40
$1.030	$2.570	$1.260	$1.130		$4.270			$5.380	41
	* $10.170			* $11.660				* $75.630	42
	* 9.840			* 10.300				* 14.060	43

Name of Respondent	This Report Is:	Date of Report	Year of Report
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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only.
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4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis, report the Btu content of the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (line 37) and average cost per unit of fuel burned (line 40) must be consistent with charges to expense accounts 501 and 547 (line 41) as show on line 19.
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: Granite City (b)			Plant Name: Key City (c)		
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)	Gas Turbine			Gas Turbine		
2	Type of Plant Construction(Conventional, Outdoor Boiler, Full Outdoor, Etc.)	Ind Enclosures			Ind Enclosures		
3	Year Originally Constructed	1969			1970		
4	Year Last Unit was Installed	1969			1970		
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	72.00			72.00		
6	Net Peak Demand on Plant -- MW (60 minutes)	62			48		
7	Plant Hours Connected to Load	47			34		
8	Net Continuous Plant Capability (Megawatts)	61			65		
9	When Not Limited by Condenser Water						
10	When Limited by Condenser Water						
11	Average Number of Employees	0			0		
12	Net Generation,Exclusive of Plant Use --KWh	2,198,000			1,530,000		
13	Cost of Plant: Land and Land Rights	40,240			67,495		
14	Structures and Improvements	474,772			155,215		
15	Equipment Costs	6,280,705			7,387,093		
16	Total Cost	$6,795,717			$7,609,803		
17	Cost per KW of Installed Capacity (line 5)	94.3849			105.6917		
18	Production Expenses: Oper. Supv. & Engr.	9,574			13,813		
19	Fuel	125,477			103,094		
20	Coolants and Water (Nuclear Plants Only)						
21	Steam Expenses						
22	Steam From Other Sources						
23	Steam Transferred (Cr.)						
24	Electric Expenses	6,018			3,078		
25	Misc. Steam (or Nuclear) Power Expenses	51,745			19,959		
26	Rents	138					
27	Allowances						
28	Maintenance Supervision and Engineering	4,538			19,328		
29	Maintenance of Structures	6			306		
30	Maintenance of Boiler (Or Reactor) Plant						
31	Maintenance of Electric Plant	64,566			290,093		
32	Maintenance Misc. Steam (or Nuclear) Plant	1,038			11		
33	Total Production Expenses	$263,100			$449,682		
34	Expenses per Net KWh	$0.1196			$0.2939		
35	Fuel: Kind (Coal,Gas,Oil,or Nuclear)		Gas			Gas	
36	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-Mcf)(Nuclear-indicate)		MCF			MCF	
37	Quantity (Units) of Fuel Burned		55,117			39,086	
38	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if nuclear)		1,016			1,015	
39	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year		$2.280			$2.640	
40	Average Cost of Fuel per Unit Burned		$2.280			$2.640	
41	Avg. Cost of Fuel Burned per Million Btu		$2.240			$2.600	
42	Avg. Cost of Fuel Burned per KWh Net Gen		* $59.240			* $64.030	
43	Average Btu per KWh Net Generation		* 26.450			* 24.640	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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

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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: * Monticello (d)	Plant Name: Inver Hills (e)	Plant Name: * Prairie Island (f)	Line No.
Nuclear	Gas Turbine	Nuclear	1
Conventional	Ind Enclosures	Conventional	2
1971	1972	1973	3
1971	1972	1974	4
568.80	326.40	1,186.20	5
543	344	1,028	6
7,423	45	8,735	7
	343		8
553		1,064	9
544		1,027	10
432	5	530	11
3,872,937,000	8,576,000	8,223,085,000	12
$767,267	$255,567	$377,794	13
102,598,362	960,974	203,785,291	14
396,670,773	31,186,847	660,935,238	15
$500,036,402	$32,403,388	$865,098,323	16
879.1075	99.2750	729.3022	17
9,031,564	66,333	12,090,229	18
18,289,424	762,097	42,795,552	19
431,789		208,358	20
11,951,908		4,860,903	21
			22
			23
1,609,763	129,763	5,647,838	24
18,937,180	107,645	25,475,739	25
366,193	167	126,149	26
			27
1,940,684	35,527	1,408,776	28
37,578	2,738	769,925	29
2,864,930		10,376,152	30
1,654,180	214,882	3,772,495	31
3,680,452	6,976	6,256,609	32
$70,795,645	$1,326,128	$113,788,725	33
$0.0182	$0.1546	$0.0138	34
Nuclear	Oil	Nuclear	35
Grams U-235	Bbls	Grams U-235	36
347,264	32,228	818,688	37
116,127	140,457	108,512	38
	$23.650		39
$52.670	$23.650	$52.270	40
$0.450	$4.010	$0.480	41
$4.720	* $88.860	$5.200	42
10.420	* 22.170	10.800	43

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 on this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis, report the Btu content of the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (line 37) and average cost per unit of fuel burned (line 40) must be consistent with charges to expense accounts 501 and 547 (line 41) as show on line 19.
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: Angus Anson (b)		Plant Name: (c)	
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)	Gas Turbine			
2	Type of Plant Construction(Conventional, Outdoor Boiler, Full Outdoor, Etc.)				
3	Year Originally Constructed	1994			
4	Year Last Unit was Installed	1994			
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	210.00			
6	Net Peak Demand on Plant -- MW (60 minutes)	232			
7	Plant Hours Connected to Load	315			
8	Net Continuous Plant Capability (Megawatts)	232			
9	When Not Limited by Condenser Water				
10	When Limited by Condenser Water				
11	Average Number of Employees	0			
12	Net Generation,Exclusive of Plant Use --KWh	32,329,000			
13	Cost of Plant: Land and Land Rights	442,375			
14	Structures and Improvements	5,779,003			
15	Equipment Costs	63,914,400			
16	Total Cost	$70,135,778			
17	Cost per KW of Installed Capacity (line 5)	333.9798			
18	Production Expenses: Oper. Supv. & Engr.	51,282			
19	Fuel	1,219,844			
20	Coolants and Water (Nuclear Plants Only)				
21	Steam Expenses				
22	Steam From Other Sources				
23	Steam Transferred (Cr.)				
24	Electric Expenses	123,502			
25	Misc. Steam (or Nuclear) Power Expenses	61,906			
26	Rents				
27	Allowances				
28	Maintenance Supervision and Engineering	738			
29	Maintenance of Structures	50,229			
30	Maintenance of Boiler (Or Reactor) Plant				
31	Maintenance of Electric Plant	6,704			
32	Maintenance Misc. Steam (or Nuclear) Plant	70,487			
33	Total Production Expenses	$1,584,692			
34	Expenses per Net KWh	$0.0490			
35	Fuel: Kind (Coal,Gas,Oil,or Nuclear)	Gas	Oil		
36	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas-Mcf)(Nuclear-indicate)	MCF	Bbls		
37	Quantity (Units) of Fuel Burned	463,501	574		
38	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas) (Give unit if nuclear)	1,013	138,028		
39	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year	$2.600	$24.100		
40	Average Cost of Fuel per Unit Burned	$2.600	$24.100		
41	Avg. Cost of Fuel Burned per Million Btu	$2.570	$4.160		
42	Avg. Cost of Fuel Burned per KWh Net Gen	* $37.730			
43	Average Btu per KWh Net Generation	* 14.630			

< Page 402 Line 42 Column b >

All Fuels - reported per MWh

< Page 402 Line 42 Column c >

All Fuels - reported per MWh

< Page 402 Line 43 Column b >

All Fuels - reported per MWh

< Page 402 Line 43 Column c >

All Fuels - reported per MWh

< Page 402.1 Line 42 Column c >

Reported per MWh

< Page 402.1 Line 43 Column c >

Reported per MWh

< Page 402.2 Line 42 Column b >

Reported per MWh

< Page 402.2 Line 42 Column c >

Reported per MWh

< Page 402.2 Line 43 Column b >

Reported per MWh

< Page 402.2 Line 43 Column c >

Reported per MWh

< Page 402.3 Line 42 Column b >

All Fuels - reported per MWh

< Page 402.3 Line 43 Column b >

All Fuels - reported per MWh

< Page 403 Line 42 Column d >

All Fuels - reported per MWh

< Page 403 Line 42 Column e >

All Fuels - reported per MWh

< Page 403 Line 42 Column f >

All Fuels - reported per MWh

< Page 403 Line 43 Column d >

All Fuels - reported per MWh

< Page 403 Line 43 Column e >

All Fuels - reported per MWh

< Page 403 Line 43 Column f >

All Fuels - reported per MWh

< Page 403.1 Column e >

Instruction 3 - Sherburne County Generating Plan (p. 403.1)

Sherburne County Generating Plant Unit 3 is jointly owned by The Company (59%) and Southern Minnesota Municipal Power Agency (41%). See Note 11 on Notes to the Financial Statements for further discussion.

< Page 403.1 Line 42 Column d >

All Fuels - reported per MWh

< Page 403.1 Line 42 Column e >

All Fuels - reported per MWh

< Page 403.1 Line 42 Column f >

Reported per MWh

< Page 403.1 Line 43 Column d >

All Fuels - reported per MWh

< Page 403.1 Line 43 Column e >

All Fuels - reported per MWh

< Page 403.1 Line 43 Column f >

Reported per MWh

< Page 403.2 Column d >

Instruction 12 - Monticello Nuclear Generating Plan (p. 403.2)

(a) Operating and maintenance costs of the Monticello Plant are charged to expenses as incurred.

(b) Northern States Power Company 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 U02 contained in zirconium alloy based cladding. The equilibrium cycle has approximately 83 metric tons of uranium metal with a nominal U-235 enrichment of 3.48 weight percent in the fresh fuel. The reactor is licensed to operate at 1670 MWth.

< Page 403.2 Column f >

Instruction 12-Prairie Island Nuclear Generating Plant (p 403.2)

(a) Operating and maintenance costs of the Prairie Island Plant are charged to expensed as incurred.

(b) Northern States Power Company 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 site has two identical Westinghouse 2 loop PWR Nuclear Power Plants. Fuel material is U02 contained in a zirconium alloy based cladding. The equilibrium cycle has approximately 43 metric tons of uranium metal with a nominal U-235 enrichment of 4.95 weight percent in the fresh fuel. Each reactor is licensed to operate at 1650 Mwth.

< Page 403.2 Line 42 Column e >

Reported per MWh

< Page 403.2 Line 43 Column e >

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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. Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Run of River	
2	Type of Plant Construction (Conventional or Outdoor)	Conventional	
3	Year Originally Constructed	1908	
4	Year Last Unit was Installed	1955	
5	Total installed Capacity (Generator Name Plate Rating in MW)	12.40	
6	Net Peak Demand on Plant-Megawatts (60 minutes)	12	
7	Plant Hours Connected to Load	NA	
8	Net Plant Capability (In megawatts)		
9	(a) Under the Most Favorable Oper. Conditions	12	
10	(b) Under the Most Adverse Oper. Conditions	2	
11	Average Number of Employees	0	
12	Net Generation, Exclusive of Plant Use-KWh	80,217,000	
13	Cost of Plant:		
14	Land and Land Rights	$1,548,707	
15	Structures and Improvements	402,364	
16	Reservoirs, Dams, and Waterways	1,862,346	
17	Equipment Costs	1,453,197	
18	Roads, Railroads, and Bridges		
19	TOTAL Cost (Enter Total of lines 14 thru 18)	$5,266,614	
20	Cost per KW of Installed Capacity (Line 5)	$424.7269	
21	Production Expenses:		
22	Operation Supervision and Engineering	130,566	
23	Water for Power	105,959	
24	Hydraulic Expenses	52,496	
25	Electric Expenses	59,064	
26	Misc. Hydraulic Power Generation Expenses	157,015	
27	Rents	40	
28	Maintenance Supervision and Engineering	24,208	
29	Maintenance of Structures	2,917	
30	Maintenance of Reservoirs, Dams, and Waterways	4,176	
31	Maintenance of Electric Plant	5,560	
32	Maintenance of Misc. Hydraulic Plant	29,083	
33	Total Production Expenses (Total lines 22 thru 32)	$571,084	
34	Expenses per net KWh	$0.0071	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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	123,324	33,159,016
4						
5						
6	INTERNAL COMBUSTION					
7						
8	Disbursed Generation				(661)	3,316,046
9						
10						
11	HYDRO PLANTS					
12						
13	Lower Dam	1887	8.00		0	624,507
14						
15						
16						
17	WIND TURBINE PLANT					
18						
19	Holland	1986	0.20		23	46,701
20						
21						
22						
23	SOLAR					
24						
25	Photovoltaic Units	1995				11,691
26						
27						
28						
29						
30						
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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 that 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 Per MW Inst Capacity (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel (i)	Production Expenses: Maintenance (j)	Kind of Fuel (k)	Fuel Cost (In cents per million Btu) (l)	Line No.
						1
						2
	1,664,831	1,490,367	2,518,101	RDF, Gas	63¢	3
						4
						5
						6
						7
	8,703	2,509	27,980	Oil	558¢	8
						9
						10
						11
						12
	3,435		1,332	Hydro		13
						14
						15
						16
						17
						18
	484		2,428	Wind		19
						20
						21
						22
						23
						24
				Solar		25
						26
						27
						28
						29
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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number of Circuits (h)
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	King (0975)	Red Rock	345.00	345.00	Tower	18.85		1
4					2 Pole K	6.12		1
5	Parkers Lake (0976)	Prairie Island	345.00	345.00	Tower	31.29		1
6					Tower	5.93		1
7					Steel Pole	4.13		1
8					Steel Pole	0.11		1
9					Stl Pole-0976		0.11	1
10					2 Pole K	25.91		1
11	King (0977)	Terminal	345.00	345.00	Tower	19.77		1
12					Steel Pole	3.23		1
13	Monticello (0978)	Parkers Lake	345.00	345.00	Tower	16.82		1
14					2 Pole K	20.33		1
15	Prairie Island (0979)	Adams	345.00	345.00	Tower	2.42		1
16					Tower	0.87		1
17					2 Pole K	72.88		1
18	Chisago Co (0980)	Coon Creek	345.00	345.00	Twr on 0977		11.19	1
19					Stl Pole-0977		3.23	1
20					Tower	6.78		1
21					Steel Pole	4.98		1
22					Steel Pole	31.56		1
23	King (0981)	St Croix River	345.00	345.00	Twr on 0975		14.80	1
24					Tower	0.62		1
25					2 Pole K	3.84		1
26	Blue Lake (0982)	Lakefield Junction	345.00	345.00	Tower	14.95		1
27					2 Pole K	112.24		1
28	Sherburne Co (0984)	Terminal	345.00	345.00	Tower	12.24		1
29					2 Pole K	16.21		1
30					Twr on 0977		1.97	1
31					Steel Pole	15.07		1
32					Stl Pole-0980		5.11	1
33					Twr on 0980		6.65	1
34	Sherburne Co (0985)	CU Conn	345.00	345.00	Tower	5.82		1
35					2 Pole K	20.33		1
36					TOTAL			

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

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	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
3-1192ACSR	$1,723,334	$60,576,836	$62,300,170					1
3-1192ACSR	2,256,696	16,330,332	18,587,028	88,937	76,674	0	* 165,611	2
2-795ACSR	$401,128	$2,382,524	$2,783,652					3
2-795ACSR								4
2-795ACSR	$2,364,126	$9,191,243	$11,555,369					5
2-954ACSR								6
2-795ACSR								7
2312ACSR								8
2312ACSR								9
2-954ACSR								10
2-795ACSR	$1,552,728	$4,076,392	$5,629,120					11
2-795ACSR			0					12
2-954ACSR	$882,197	$4,529,687	$5,411,884					13
2-954ACSR								14
2-954ACSR	$187,240	$10,323,875	$10,511,115					15
2-795ACSR								16
2-795ACSR								17
2-795ACSR	$4,872,483	$12,978,572	$17,851,055					18
2-795ACSR								19
2-795ACSR								20
2-795ACSR								21
2-954ACSR								22
2-795ACSR	$24,099	$595,169	$619,268					23
2-795ACSR								24
2-795ACSR								25
2-795ACSR	$1,308,883	$14,302,944	$15,611,827					26
2-795ACSR								27
2-954ACSR	$667,056	$8,096,993	$8,764,049					28
2-954ACSR								29
2-795ACSR								30
2-795ACSR								31
2-795ACSR								32
2-795ACSR								33
2-954ACSR	$17,816	$4,285,098	$4,302,914					34
2-954ACSR								35
								36

Name of Respondent	This Report Is:	Date of Report	Year of Report
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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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle,3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number of Circuits (h)
1	Sherburne Co (0985)	Cu Conn	345.00	345.00	Twr on 0978		7.11	1
2	Prairie Island (0986)	Red Rock	345.00	345.00	Tower	3.05		1
3					Twr on 0979		2.42	1
4					2 Pole K	19.91		1
5					Steel Pole	6.48		1
6	Prairie Island (0987)	Red Rock	345.00	345.00	Stl Pole-0986		6.48	1
7					2 Pole K	19.52		1
8					Twr on 0986		2.16	1
9					Tower	1.28		1
10					Twr on 0976		2.57	1
11	Parkers Lake (0988)	Blue Lake	345.00	345.00	Tower		11.56	1
12					Steel Pole		3.30	1
13	Blue Lake (0989)	Red Rock	345.00	345.00	Tower	7.62		1
14					Twr on 0976		19.10	1
15					Steel Pole	0.58		1
16					Stl Pole-0976		0.83	1
17					2 Pole K	3.03		1
18	Sherburne Co (0991)	Monticello	345.00	345.00	Twr on 0985		5.78	1
19	Sherburne Co (0992)	Coon Creek	345.00	345.00	Tower	0.88		1
20					2 Pole K	16.21		1
21					Stl Pole-0984		15.07	1
22					Twr on 0984		11.34	1
23	Sherburne Co (0993)	CPA Interconn	345.00	345.00	Steel Pole	10.55		1
24	Chisago Co (0994)	King	345.00	345.00	Twr on 0977		6.61	1
25					Stl Pole-0980		31.56	1
26	Parkers Lake (0996)	CU Conn	345.00	345.00	Twr on 0978		9.64	1
27	Split Rock (0997)	WAPA (Watertwn)	345.00	345.00	Steel Pole	5.10		1
28	Split Rock (0998)	WAPA (Sioux Cty)	345.00	345.00	Steel Pole		5.10	1
29	Black Dog (0900)	WAPA	230.00	230.00	Tower	115.45		1
30					2 Pole K	1.19		1
31	Red Rock (0902)	MP Co.	230.00	230.00	2 Pole K	66.55		1
32					2 Pole K	9.77		1
33					Tower	4.05		1
34	Audobon (0909)	Badura	230.00	230.00	2 Pole H	38.31		1
35	Maple River (0910)	Minnkota Conn	230.00	230.00	Tower	3.66		1
36					TOTAL			

Name of Respondent	This Report Is:	Date of Report	Year of Report
Northern States Power Company (Minnesota)	(1) [x] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 1996

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	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
2-954ACSR								1
2-795ACSR	661,692	2,927,358	3,589,050					2
2-954ACSR								3
2-795ACSR								4
2-795ACSR								5
2-795ACSR	0	$2,190,036	$2,190,036					6
2-795ACSR								7
2-795ACSR								8
2-795ACSR								9
2-954ACSR								10
2-795ACSR	0	$478,209	$478,209					11
2-795ACSR								12
2-795ACSR	$353,005	$2,932,822	$3,285,827					13
2-795ACSR								14
2-795ACSR								15
2-795ACSR								16
2-795ACSR								17
2-954ACSR	0	$196,978	$196,978					18
2-954ACSR	$472,775	$3,331,070	$3,803,845					19
2-954ACSR								20
2-954ACSR								21
2-954ACSR								22
2-1192ACSR	$958,867	$3,456,198	$4,415,065					23
2-795ACSR	0	$1,648,291	$1,648,291					24
2-954ACSR								25
2-954ACSR	0	$491,361	$491,361					26
2-954ACSR	$139,860	$2,945,436	$3,085,296					27
2-954ACSR	0	$446,776	$446,776	$101,781	$456,934	$182,365	* $741,080	28
795ACSR	$450,318	$4,505,637	$4,955,955				0	29
795ACSR								30
795ACSR	$437,738	$2,660,248	$3,097,986					31
1272ACSR								32
1272ACSR								33
795ACSR	$57,863	$1,210,723	$1,268,586					34
795ACSR	$55,625	$283,964	$339,589					35
								36

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle,3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number of Circuits (h)
1	Maple River (0911)	OTP Co	230.00	230.00	Twr on 0910		3.61	1
2		Interconn	230.00	230.00	2 Pole H	4.36		1
3	Drayton (0912)	Manitoba Hydro Interconn	230.00	230.00	2 Pole H	28.69		1
4	Sheyenne (0915)	WAPA	230.00	230.00	2 Pole H	4.26		1
5	Prairie (0916)	Minnkota-Grand Forks	230.00	230.00	2 Pole H	6.64		1
6	Mankato (5300)	Winnebago	161.00	161.00	2 Pole H	38.86		1
7	Split Rock (5301)	Heron Lake	161.00	161.00	2 Pole H	19.97		1
8	Various		115.00			1,151.74	85.09	
9	Various		69.00			1,737.90	45.53	
10	Various		34.50			67.30	0.70	
11	Various		23.00			5.55	1.20	
12	Various		115.00		Underground	7.72		
13	Various		69.00		Underground	1.59		
14	Various		13.80		Underground	0.32		
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	4,146.74	319.82	77

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
795ACSR	$31,735	$674,935	$706,670					1
795ACSR								2
954ACSR	$57,281	$758,399	$815,680					3
795ACSR	$21,223	$519,990	$541,213					4
954ACSR	$3,103	$1,023,620	$1,026,723	$44,691	$78,891	$281	* $123,863	5
477ACSR	$112,192	$715,520	$827,712					6
477ACSR	$56,236	$984,590	$1,040,826	$2,510	$43,709	$173	* $46,392	7
	$10,515,220	$85,566,012	$96,081,232	$205,766	$805,654	$280,651	* $1,292,071	8
	$3,379,614	$53,866,333	$57,245,947	$267,722	$1,875,425	$45,913	* $2,189,060	9
	$242	$1,012,120	$1,012,362	$3,422	$3,712	$1,166	* $8,300	10
	0	$363,854	$363,854	$511	$36,725	$680	* $37,916	11
	0	$12,017,527	$12,017,527	$29,935	$26,160		* $56,095	12
	0	$798,244	$798,244					13
	0	$34,380	$34,380					14
								15
								16
								17
								18
								19
								20
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								34
								35
	$34,022,375	$335,710,296	$369,732,671	$745,275	$3,403,884	$511,229	$4,660,388	36

< Page 423 Line 2 Column p >

Total expenses for all 500KV overhead transmission lines.

< Page 423.1 Line 28 Column p >

Total expenses for all 345KV overhead transmission lines.

< Page 423.2 Line 5 Column p >

Total expenses for all 230KV overhead transmission lines.

< Page 423.2 Line 7 Column p >

Total expenses for all 161KV overhead transmission lines.

< Page 423.2 Line 8 Column p >

Total expenses for all 115KV overhead transmission lines.

< Page 423.2 Line 9 Column p >

Total expenses for all 69KV overhead transmission lines.

< Page 423.2 Line 10 Column p >

Total expenses for all 34.5KV overhead transmission lines.

< Page 423.2 Line 11 Column p >

Total expenses for all 23KV overhead transmission lines.

< Page 423.2 Line 12 Column p >

Total expenses for all 115KV underground transmission lines.

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Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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 underground 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 estimated final completion

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Chisago	Wyoming	9.60	Pole	19.00	1	1
2	Chisago	Wyoming	4.90	Pole	13.00	2	2
3	West Hastings	Koch	4.97	Pole	15.00	1	1
4	West Hastings	Koch	1.58	Pole	17.00	1	1
5	Chemolite	West Hastings	7.67	Pole	19.00	1	1
6	Hastings	West Hastings	3.03	Pole	16.00	2	2
7							
8	Riverside (Underground)	Aldrich	1.70			1	1
9							
10							
11							
12							
13							
14							
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43							
44	TOTAL		33.45		99.00	9	9

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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)	LINE COST				Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Device (n)	Total (o)	
795	SSAC		115		$1,693,749	$1,033,595	$2,727,344	1
795	SSAC		115		846,873	456,009	1,302,882	2
795	SAC		115		590,348	491,956	1,082,304	3
795	SAC		115		196,782	98,362	295,144	4
795	SAC		115		814,322	557,160	1,371,482	5
336	ACSR		69		64,288	53,200	117,488	6
								7
2000	SSAC		115			2,281,934	2,281,934	8
								9
								10
								11
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				0	$4,206,362	$4,972,216	$9,178,578		44

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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	PAYNESVILLE TRANS	Trans U	115.00	36.20	
2		Trans U	115.00	69.00	13.80
3	FRANKLIN STATION	Trans U	115.00	70.60	13.80
4		Trans U	69.00	13.00	
5		Trans U	69.00	4.30	
6	LINCOLN COUNTY SUB	Trans U	115.00	13.80	
7		Trans U	115.00	40.70	13.80
8	PRAIRIE SUBSTATION	Trans U	115.00	40.70	13.80
9		Trans U	115.00	40.80	13.80
10		Trans U	230.00	168.10	
11	WEST COON RAPIDS	Trans U	69.00	13.00	7.50
12		Trans U	115.00	66.00	2.40
13		Trans U	69.00		
14		Trans U	115.00	78.70	2.40
15		Trans U	69.00	13.80	7.90
16		Trans U	69.00	13.00	
17	DOUGLAS COUNTY	Trans U	115.00	70.60	35.30
18	ALLEN S KING	Trans A	345.00	68.00	13.80
19		Trans A	345.00	199.20	20.00
20	GRANT NO CANISTOTA JCT GRANT TWP	Trans U	115.00	72.00	2.40
21	WEST GATE STATION EDEN PRAIRIE	Trans U	115.00	40.70	13.80
22		Trans U	115.00	36.20	
23		Trans U	115.00	70.60	
24		Trans U	115.00	13.80	7.90
25		Trans U	115.00	14.40	
26	PARKERS LAKE	Trans U	115.00	14.40	8.30
27		Trans U	115.00	13.80	7.90
28		Trans U	345.00	199.10	118.00
29		Trans U	345.00	115.00	13.80
30	WEST FARIBAULT SUB	Trans U	115.00	40.70	2.50
31		Trans U	69.00		
32		Trans U	69.00	13.80	7.90
33		Trans U	115.00	70.60	2.50
34	MONTICELLO SUBSTATION MONTICELLO	Trans A	345.00	199.20	22.00
35		Trans A	345.00	118.00	13.80
36		Trans A	345.00	199.20	13.80
37	MAPLE RIVER SUBSTATION REED TWP	Trans U	230.00	68.20	13.80
38	ROGERS LAKE STATION MENDOTA HEIGHTS	Trans U	115.00	70.60	13.80
39		Trans U	115.00	14.40	8.30
40	CANNON FALLS TRANS SUB RANDOLPH TWP	Trans A	161.00	68.10	13.80

SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
12.50	2	1	Regulators	2	2	1
37.50	2		Capacitor Bank	1	14	2
93.33	2		Regulators	6	1	3
4.68	1					4
1.00	1					5
28.00	1		Capacitor Bank	2	29	6
70.00	1					7
70.00	1		Capacitor Bank	7	280	8
140.00	2					9
187.00	1					10
6.25	1	1	Regulators	6	2	11
23.40	3					12
7.84	1					13
24.00	3					14
5.00	1					15
6.25	1					16
46.66	1		Capacitor Bank	1	14	17
448.00	1		Grounding Bank	3	1	18
784.00	1					19
18.75	1					20
46.66	1					21
70.00	1					22
46.66	1					23
46.66	1					24
46.66	1					25
46.66	1		Grounding Bank	3	1	26
93.33	2		Capacitor Bank	3	240	27
300.00	2					28
600.00	4					29
70.00	1		Regulators	2	2	30
22.40	1					31
28.65	2					32
50.00	2					33
728.00	1					34
280.00	1					35
336.00	1					36
186.66	1					37
46.66	1					38
93.33	2					39
186.66	1					40

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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			Trans A	115.00	70.60	
2			Trans A	115.00	70.60	35.30
3			Trans A	69.00	13.80	7.90
4	ST CLOUD		Trans A	34.00	19.00	
5			Trans A	34.00	4.30	2.50
6			Trans A	34.00	19.00	2.40
7			Trans A	115.00	63.50	36.20
8			Trans A	69.00		
9	RED ROCK STATION		Trans U	345.00	118.00	13.80
10			Trans U	345.00	118.00	68.10
11			Trans U	345.00	199.20	22.00
12			Trans U	115.00	14.40	8.30
13			Trans U	115.00		
14	ADAMS SUBSTATION	LODI TWP	Trans U	345.00	34.50	16.50
15			Trans U	15.00	2.40	
16	LAKE YANKTON		Trans U	115.00	72.00	2.30
17			Trans U	69.00	14.40	2.40
18			Trans U	115.00	72.00	13.80
19	CROW RIVER STATION	FRANKLIN TWP	Trans U	115.00	40.70	13.80
20	SCOTT COUNTY STATION	JACKSON TWP	Trans U	115.00	40.70	13.80
21	CARVER COUNTY STATION	BENTON TWP	Trans U	115.00	69.00	
22	INVER GROVE STATION	INVER GROVE HGTS	Trans U	115.00	70.60	13.80
23	WAKEFIELD STATION		Trans U	69.00	13.20	2.20
24			Trans U	69.00	13.80	
25			Trans U	69.00	36.40	13.20
26			Trans U	115.00	69.00	34.50
27			Trans U	69.00	36.60	18.30
28	CHISAGO COUNTY SUB		Trans U	500.00	345.00	34.50
29			Trans U	345.00	118.00	68.10
30			Trans U			
31	RIVERSIDE SUBSTATION	MPLS	Trans A	15.00		
32			Trans A	115.00	14.40	8.30
33			Trans A	115.00	13.80	
34			Trans A	115.00	66.50	15.30
35			Trans A	115.00	13.80	
36	HIGH BRIDGE SUBSTATION	ST PAUL	Trans A	115.00	70.60	
37	BLACK DOG SUBSTATION	BURNSVILLE	Trans A	115.00	13.80	
38			Trans A	230.00	118.00	
39	WILMARTH		Trans A	115.00	40.70	13.80
40			Trans A	345.00	68.10	13.80

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
46.60	1					1
46.66	1					2
10.50	1					3
3.00	3		Regulators	3	2	4
3.75	1		Grounding Bank	2	18	5
4.68	3					6
83.33	2					7
0.03	1					8
448.00	1		Regulators	1	1	9
448.00	1		Capacitor Bank	3	248	10
336.00	1					11
46.66	1					12
40.00	2					13
300.00	1					14
0.03	3					15
15.00	1	1	Grounding Bank	1	40	16
2.50	3					17
15.00	1					18
112.00	1					19
132.50	2					20
70.00	1					21
125.00	2					22
0.62	1		Regulators	1	19	23
0.66	1		Grounding Bank	1	6	24
1.25	2					25
10.00	1					26
18.75	3					27
1,604.00	4	1	Regulators	3	1	28
448.00	1		Grounding Bank	7	10	29
			Capacitor Bank	1	468	30
0.10	1					31
93.66	2					32
47.00	1					33
18.75	1					34
275.00	1					35
192.00	1					36
558.00	5					37
186.66	1					38
210.00	3		Regulators	6	5	39
448.00	1		Grounding Bank	2	159	40

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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			Trans A	69.00	13.80	
2			Trans A	161.00	68.10	13.80
3			Trans A	69.00	13.00	
4	MINNESOTA VALLEY		Trans A	69.00	38.10	13.80
5			Trans A	115.00	72.00	13.80
6			Trans A	115.00	70.60	13.80
7			Trans A	115.00	13.80	
8			Trans A	230.00	115.00	6.90
9			Trans A	23.00	13.80	
10	LAWRENCE SUBSTATION	MAPLETON TWP	Trans A	115.00	40.60	13.80
11			Trans A	69.00	13.80	
12			Trans A	115.00	70.60	13.80
13			Trans A	115.00	40.70	13.80
14	BENTON COUNTY SUB	MINDEN TWP	Trans U	230.00	118.00	13.80
15			Trans U	230.00	118.00	13.80
16	PATHFINDER SUBSTATION	BRANDON TWP	Trans A	115.00	66.40	13.80
17	RED WING		Trans A	69.00	13.80	
18	GRANITE CITY		Trans U	115.00	36.20	20.90
19			Trans U	115.00	14.40	
20	LAKE PULASKI SUBSTATION	BUFFALO TWP	Trans U	115.00	36.20	20.00
21			Trans U	115.00	40.70	35.00
22	PRAIRIE ISLAND SUB	RED WING-URBAN	Trans A	345.00	60.00	20.00
23			Trans A	345.00	161.00	13.80
24	COON CREEK SUBSTATION	COON RAPIDS	Trans U	345.00	118.00	13.80
25	INVER HILLS SUBSTATION	INVER GROVE HGTS	Trans A	115.00	14.40	
26			Trans A	345.00	118.00	13.80
27			Trans A	115.00	14.00	
28	BLUE LAKE		Trans U	115.00	13.80	7.90
29			Trans U	115.00	14.40	
30			Trans U	345.00	118.00	13.80
31	KOHLMAN LAKE		Trans U	115.00	14.40	8.30
32			Trans U	345.00	118.00	13.80
33			Trans U	345.00	68.10	13.80
34	SHERBURNE COUNTY SUB	BECKER	Trans U	345.00	26.00	
35			Trans U	345.00	24.00	
36			Trans U	345.00	199.20	24.00
37	FORT RIDGELY SUBSTATION	LAFAYETTE TWP	Trans U	115.00	70.60	13.80
38	SPLIT ROCK		Trans U	161.00	116.00	13.80
39			Trans U	345.00	68.10	13.80
40	EDEN PRAIRIE SUBSTATION	EDEN PRAIRIE	Trans U	345.00	68.10	13.80

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SUBSTATIONS (Continued)

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

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Capacity of Substation (In Service) (In MVa)	Number of Transformers in Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
121.45	5					1
112.00	1					2
28.00	1					3
25.00	6	1	Regulators	2	1	4
41.66	1					5
46.66	1					6
50.00	1					7
100.00	2					8
7.50	6					9
46.66	1					10
20.00	1					11
46.66	1					12
112.00	1					13
186.66	1					14
186.00	1					15
85.00	1					16
40.00	4		Regulators	6	4	17
70.00			Regulators	3	3	18
93.33						19
28.00	1					20
70.00	1					21
1,344.00	2					22
224.00	1					23
448.00	1					24
280.00	2					25
550.00	1					26
140.00	1					27
50.00	2		Regulators	6	9	28
246.00	2					29
336.00	1					30
47.00	1		Grounding Bank	1	40	31
448.00	1		Capacitor Bank	3	248	32
448.00	1					33
672.00	1					34
800.00	1					35
1,600.00	2					36
70.00	1					37
93.33	2		Capacitor Bank	1	41	38
896.00	2					39
448.00	1					40

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SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.

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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			Trans U	115.00	14.40	8.30
2	FORBES SUBSTATION		Trans U	500.00	20.00	
3	SHEYENNE		Trans U	230.00	13.80	
4	LOON LAKE SUB		Trans U			
5	ROSEAU COUNTY SUB		Trans U			
6	LITTLEFORK		Trans U			
7	BUFFALO RIDGE SUB	LAKE BENTON TWP	Trans U	115.00	34.50	19.90
8			Trans U	115.00	36.20	20.90
9	GOPHER SUBSTATION	MPLS	Distr U	115.00	14.40	8.30
10	GARFIELD		Distr U	15.00	4.20	
11			Distr U	15.00	4.20	2.40
12	ELM CREEK SUBSTATION	MAPLE GROVE	Distr U	115.00	13.80	7.90
13	MAIN STREET SUBSTATION	MPLS	Distr A	15.00	2.40	
14			Distr A	115.00	14.40	
15	MARSHALL		Distr U	15.00	4.30	2.50
16	NICOLLET		Distr U	15.00	4.20	2.40
17			Distr U	15.00	4.20	
18	OAKLAND SUBSTATION		Distr U	15.00	4.20	2.40
19	OSSEO SUBSTATION	MAPLE GROVE	Distr U	115.00	14.40	
20			Distr U	115.00	14.40	8.30
21	QUINCY SUBSTATION		Distr U	15.00	4.30	
22	ST LOUIS PARK SUB		Distr U	115.00	14.40	8.30
23			Distr U	15.00	8.60	
24			Distr U	115.00	13.80	
25	ELLIOT PARK SUBSTATION	MPLS	Distr U	115.00	14.40	
26			Distr U	115.00	14.40	8.30
27	TWIN LAKE SUBSTATION	BROOKLYN CENTER	Distr U	115.00	14.40	8.30
28	ALDRICH SUBSTATION	MPLS	Distr U	115.00	14.40	8.30
29	SOUTHTOWN SUBSTATION	MPLS	Distr U	115.00	14.00	
30			Distr U	115.00	63.50	14.40
31	WILSON SUBSTATION		Distr U	115.00	64.90	13.80
32			Distr U	115.00	13.80	
33			Distr U	115.00	14.40	
34	TERMINAL		Distr U	115.00	13.80	7.90
35			Distr U	115.00	13.80	
36			Distr U	345.00	118.00	34.50
37			Distr U	15.00	4.30	
38	NINE MILE CREEK SUBST	EDINA	Distr U	115.00	13.80	7.90
39	EDINA SUBSTATION	EDINA	Distr U	115.00	14.40	
40	MEDICINE LAKE SUBST	GOLDEN VALLEY	Distr U	115.00	14.40	8.30

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: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
93.33	2					1
168.00	1		Capacitor Bank	2	600	2
187.00	1		Capacitor Bank	5	200	3
			Capacitor Bank	1	18	4
			Capacitor Bank	4	390	5
			Capacitor Bank	6	180	6
240.00	2					7
28.00	1					8
93.33	2					9
7.50	3		Regulators	30	2	10
7.50	3					11
25.00	1					12
0.50	1					13
140.00	2					14
5.00	1		Regulators	24	2	15
5.00	1		Regulators	21	2	16
10.00	2					17
15.00	6		Regulators	18	1	18
70.00	1					19
140.00	2					20
10.00	2		Regulators	12	1	21
140.00	2		Grounding Bank	2	5	22
8.34	3					23
68.61	4					24
46.70	1					25
93.66	2					26
210.00	3					27
140.00	2					28
125.00	2					29
70.00	1					30
20.00	2		Grounding Bank	2	10	31
40.00	4					32
200.00	2					33
25.00	1		Regulators	18	1	34
75.00	3					35
1,344.00	2					36
15.00	2					37
28.00	1					38
270.00	3					39
70.00	1					40

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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			Distr U	115.00	14.40	
2	SAVAGE SUBSTATION		Distr U	115.00	13.80	7.90
3			Distr U	115.00	13.00	7.90
4	MOORE LAKE SUBSTATION	FRIDLEY	Distr U	115.00	14.40	
5			Distr U	115.00	13.70	
6	AIRPORT SUBSTATION	METRO AIRPORT	Distr U	115.00	14.40	
7	BLOOMINGTON SUBSTATION	BLOOMINGTON	Distr U	115.00	13.80	
8			Distr U	15.00		
9			Distr U	115.00	13.80	7.90
10	RIVERWOOD SUBSTATION	BURNSVILLE	Distr U	115.00	13.80	
11	BROOKLYN PARK SUB	BROOKLYN PARK	Distr U	115.00	13.80	7.90
12	APACHE SUBSTATION	ST ANTHONY	Distr U	115.00	14.40	
13	INDIANA SUBSTATION	ROBBINSDALE	Distr U	115.00	14.40	8.30
14			Distr U	115.00	13.80	7.90
15	BASSETT CREEK SUB	PLYMOUTH	Distr U	115.00	14.40	8.30
16	FIFTH STREET SUBSTATION	MPLS	Distr U	115.00	13.80	
17	CROOKED LAKE SUBSTATION	COON RAPIDS	Distr U	115.00	13.80	7.90
18			Distr U	118.00	13.80	
19	HYLAND LAKE SUBSTATION	BLOOMINGTON	Distr U	115.00	14.40	8.30
20	DODGE CENTER		Distr U	69.00	13.80	7.90
21	FARIBAULT		Distr U	69.00	13.00	
22			Distr U	69.00	4.20	2.30
23	FARMINGTON SUBSTATION	FARMINGTON	Distr U	69.00	13.80	
24			Distr U	69.00	13.80	7.90
25	HASTINGS SUBSTATION	HASTINGS	Distr U	69.00	13.80	7.90
26	WASECA SUBSTATION		Distr U	69.00	4.30	2.50
27			Distr U	69.00	15.10	7.50
28			Distr U	69.00	13.80	7.90
29	ZUMBROTA		Distr U	69.00	14.40	2.40
30			Distr U	69.00	13.00	4.30
31	PINE ISLAND		Distr U	69.00	13.00	7.50
32			Distr U			
33	AIRLAKE SUBSTATION	LAKEVILLE	Distr U	69.00	13.80	7.90
34	NORTHFIELD		Distr U	69.00	13.80	
35	WATERVILLE		Distr U	69.00	15.10	7.50
36			Distr U	69.00	14.70	4.20
37			Distr U	69.00	4.30	2.50
38	FAIR PARK		Distr U	69.00	13.80	7.90
39	KASSON SUBSTATION		Distr U	69.00	13.80	7.90
40	BECKER SUBSTATION		Distr U	69.00	35.30	20.30

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140.00	2					1
28.00	1		Regulators	6	4	2
25.00	1					3
140.00	2					4
50.00	1					5
93.33	2					6
93.33	2					7
0.02	1					8
25.00	1					9
25.00	1					10
50.00	1					11
140.00	2					12
28.00	1					13
39.20	1					14
28.00	1					15
336.00	4					16
93.33	2					17
28.00	1					18
93.33	2					19
10.50	1		Capacitor Bank	1	5	20
14.00	1		Regulators	12	1	21
7.95	3		Capacitor Bank	1	7	22
14.00	1					23
10.50	1					24
67.50	2					25
7.80	2		Regulators	8	3	26
14.00	1					27
12.50	1					28
1.50	3		Regulators	5	1	29
7.00	1		Capacitor Bank	1	7	30
7.00	1		Regulators	2	1	31
			Capacitor Bank	1	7	32
36.00	2					33
28.00	1		Grounding Bank	3	1	34
5.60	1		Regulators	8	1	35
1.87	3		Capacitor Bank	1	7	36
1.50	1					37
21.00	2		Capacitor Bank	1	7	38
9.37	1		Regulators	5	3	39
4.68	1		Regulators	1	1	40

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1		Distr U	118.00	36.20	20.00
2	COLD SPRING	Distr U	69.00	34.40	4.30
3		Distr U	34.00	17.30	2.40
4	EDEN VALLEY	Distr U	34.00	4.10	2.40
5	GLENWOOD	Distr U	69.00	13.00	
6		Distr U	69.00	38.70	4.10
7		Distr U	69.00	4.10	2.40
8	INDUSTRIAL	Distr U	34.00	12.50	4.30
9		Distr U	34.00	4.30	2.50
10	LINN STREET	Distr U	69.00	13.00	7.50
11	ST JOSEPH	Distr U	69.00	13.00	7.50
12		Distr U			
13	ALBANY SUBSTATION	Distr U	15.00	4.30	2.50
14		Distr U	69.00	34.40	7.20
15	EMPIRE PARK SUBSTATION ST CLOUD	Distr U	34.00	4.30	2.50
16	SOUTHSIDE	Distr U	68.80	13.00	7.50
17	M.E. INTERNATIONAL SUB ST CLOUD	Distr U	110.00	13.80	
18	CROSSROADS SUBSTATION ST CLOUD	Distr U	115.00	13.80	
19		Distr U	115.00	13.80	7.90
20	SALIDA CROSSING SUB BECKER	Distr U	115.00	13.80	
21	PIPESTONE	Distr U	69.00	24.10	13.90
22		Distr U	115.00	72.00	13.80
23		Distr U	69.00	4.30	2.50
24	CHERRY CREEK	Distr U	69.00	12.90	7.50
25		Distr U	115.00	14.40	8.30
26	CLIFF AVENUE	Distr U	69.00	13.00	
27		Distr U	69.00	4.30	
28	DELL RAPIDS	Distr U	69.00	13.80	7.90
29	SILVER CREEK SUBSTATION SIOUX FALLS	Distr U	69.00	13.80	7.90
30		Distr U	69.00	13.80	
31	SIOUX FALLS	Distr U	69.00	13.80	7.90
32	SOUTH SIOUX FALLS	Distr U	69.00	4.30	2.50
33		Distr U	69.00	13.80	7.90
34	TRACY SWITCHING	Distr U	69.00	13.80	7.90
35		Distr U			
36	WEST SIOUX FALLS	Distr U	115.00	70.60	13.80
37		Distr U	69.00	4.30	2.50
38		Distr U	115.00	14.40	8.30
39		Distr U	15.00	4.10	2.40
40	MINNEHAHA SUBSTATION SIOUX FALLS	Distr U	115.00	14.40	

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
7.00	1					1
7.00	1		Regulators	5	1	2
3.75	3					3
1.00	2		Regulators	3	1	4
5.25	1		Regulators	6	1	5
2.50	1		Capacitor Bank	1	7	6
7.50	3					7
12.50	2		Regulators	3	1	8
1.50	3					9
21.00	2		Regulators	12	2	10
4.20	1		Regulators	6	1	11
			Capacitor Bank	1	11	12
6.25	1		Regulators	6	1	13
10.50	1					14
14.00	2					15
	1		Regulators	1	1	16
16.60	1					17
50.00	2					18
22.40	1					19
14.00	1					20
6.25	1		Regulators	15	1	21
25.00	1					22
18.75	2					23
0.15	1		Regulators	9	3	24
37.35	1					25
10.50	1		Regulators	8	1	26
6.66	1					27
9.37	1		Regulators	6	1	28
10.50	1					29
10.50	1					30
56.00	2		Regulators	1	1	31
12.91	2		Regulators	9	1	32
56.00	2					33
5.25	1		Regulators	3	1	34
			Capacitor Bank	1	5	35
70.00	1		Regulators	4	1	36
6.25	1					37
140.00	2					38
0.33	1					39
56.00	2					40

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

SUBSTATIONS

1. Report below the information called for concerning substations c[illegible] 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	CANISTOTA JUNCTION	Distr U	69.00	13.80	
2		Distr U			
3	HASSAN SUBSTATION HASSAN TWP	Distr U	115.00	36.20	20.90
4	LESTER PRAIRIE	Distr U	69.00	13.80	
5		Distr U			
6	MONTEVIDEO	Distr U	69.00	13.00	
7		Distr U	69.00	4.30	
8	WINSTED SUBSTATION	Distr U	69.00	13.80	7.90
9	YOUNG AMERICA	Distr U	69.00	13.80	7.90
10		Distr U	69.00	13.80	
11	CREDIT RIVER SUBSTATION PRIOR LAKE	Distr U	69.00	13.00	
12	WYOMING SUBSTATION	Distr U	69.00		
13		Distr U	69.00	13.00	
14	FOREST SUBSTATION	Distr U	15.00	4.30	2.50
15		Distr U			
16	PRIOR SUBSTATION ST PAUL	Distr U	115.00	14.40	8.30
17	AFTON SUBSTATION AFTON	Distr U	115.00	36.20	20.90
18	ROSE PLACE SUBSTATION ROSEVILLE	Distr U	115.00	14.40	8.30
19	BATTLE CREEK SUBSTATION ST PAUL	Distr U	115.00	14.40	8.30
20	ST CLAIR	Distr U	15.00	4.30	2.50
21	OAKDALE SUBSTATION OAKDALE	Distr U	115.00	14.40	8.30
22	BAYTOWN SUBSTATION OAK PARK HGTS	Distr U	115.00	14.40	8.30
23	BIRCH SUBSTATION	Distr U	69.00	36.20	
24	RAMSEY SUBSTATION	Distr U	115.00	13.60	
25		Distr U			
26	MERRIAM PARK SUBSTATION ST PAUL	Distr U	115.00	14.00	
27	WESTERN SUBSTATION ST PAUL	Distr U	115.00	14.40	8.30
28	KOCH REFINERY	Distr U	69.00		
29		Distr U	115.00	14.40	8.30
30		Distr U	69.00	13.00	7.50
31		Distr U	15.00	4.10	
32		Distr U	69.00	4.30	2.50
33	WILLIAMS BROS	Distr U	15.00	8.60	
34		Distr U	15.00	4.30	2.50
35		Distr U	115.00	14.00	
36	STOCKYARDS SUBSTATION SOUTH ST PAUL	Distr U	115.00	13.80	7.90
37	DAYTONS BLUFF SUBST ST PAUL	Distr U	115.00	14.00	
38	PINE BEND	Distr U	69.00	13.50	7.90
39		Distr U	69.00	4.30	2.50
40	TANNERS LAKE SUBSTATION MAPLEWOOD	Distr U	15.00	12.40	7.20

SUBSTATIONS (Continued)

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

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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: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
7.50	1		Regulators	1	1	1
			Capacitor Bank	2	5	2
70.00	1					3
7.50	1		Regulators	2	2	4
			Grounding Bank	1	10	5
5.25	1		Regulators	10	1	6
6.00	1		Grounding Bank	1	5	7
10.72	1		Regulators	3	1	8
9.37	1		Regulators	6	2	9
10.50	1		Grounding Bank	3	2	10
14.00	1					11
2.58	1		Regulators	8	4	12
17.58	1					13
20.00	2		Regulators	19	2	14
			Grounding Bank	3	2	15
28.00	1					16
93.33	2					17
93.33	2					18
93.33	2					19
10.00	2		Regulators	18	1	20
93.33	2					21
28.00	1					22
16.80	1		Regulators	3	1	23
100.00	2		Regulators	11	6	24
			Grounding Bank	2	7	25
187.50	3					26
140.00	2					27
56.00	2		Capacitor Bank	1	62	28
140.10	3					29
18.75	2					30
28.00	1					31
25.00	4					32
2.78	1		Regulators	1	1	33
7.50	1					34
9.37	1					35
93.33	2					36
187.50	3					37
9.37	1		Regulators	1	1	38
10.00	2					39
23.33	7					40

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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		Distr U	15.00	8.33	7.20
2		Distr U	15.00	12.40	
3		Distr U	15.00	8.30	7.20
4		Distr U	115.00	14.40	8.30
5	UPPER LEVEE SUBSTATION ST PAUL	Distr U	115.00	14.40	8.30
6		Distr U	115.00	14.40	
7	CHEMOLITE	Distr U	115.00	40.70	13.80
8		Distr U	115.00		
9		Distr U	115.00	13.00	
10	RONDO SUBSTATION	Distr U	15.00	4.30	2.50
11	LINDE SUBSTATION	Distr U	115.00	13.60	
12		Distr U	115.00	14.40	8.30
13	ARDEN HILLS	Distr U	115.00	70.60	15.00
14		Distr U	115.00	40.70	13.80
15	SHEPARD SUBSTATION ST PAUL	Distr U	115.00	13.80	
16	NORTH STAR STEEL SUB ST PAUL	Distr U	115.00	13.80	7.90
17		Distr U	115.00	13.60	
18	COTTAGE GROVE SUB COTTAGE GROVE	Distr U	115.00	14.40	
19	LEXINGTON SUBSTATION ARDEN HILLS	Distr U	115.00	36.20	20.90
20		Distr U	115.00	13.80	7.90
21		Distr U	34.00	14.40	
22	CEDARVALE	Distr U	115.00	13.80	
23		Distr U	115.00	13.80	7.90
24	MAXWELL SUBSTATION ST PAUL	Distr U	115.00	4.10	2.30
25	LONE OAK SUBSTATION EAGAN	Distr U	69.00	13.80	7.90
26	WOODBURY SUBSTATION WOODBURY	Distr U	115.00	36.20	19.90
27	WEST BYRON	Distr U	69.00	12.50	
28	EASTWOOD SUBSTATION MANKATO TWP	Distr U	69.00	13.80	
29	SIBLEY PARK SUBSTATION MANKATO	Distr U	69.00	13.80	7.90
30	ST JAMES MUNICIPAL SUB ST JAMES	Distr U	69.00	12.40	7.20
31	HUGO SUBSTATION	Distr U	69.00	13.00	7.50
32	OAK PARK SUBSTATION OAK PARK HGTS	Distr U	118.00	68.60	2.70
33		Distr U	118.00	68.60	15.40
34		Distr U	118.00	68.60	
35		Distr U	118.00	14.40	6.40
36	GOOSE LAKE SUBSTATION WHITE BEAR TWP	Distr U	115.00	70.60	
37		Distr U	115.00	14.40	7.90
38	MINNESOTA PIPELINE SUB HUGO	Distr U	68.80	13.09	2.50
39	LINDSTROM SUBSTATION CHISAGO LAKE TWP	Distr U	15.00		
40		Distr U	69.00	13.80	7.90

SUBSTATIONS (Continued)

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

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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: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
29.99	9					1
9.99	3					2
9.99	3					3
140.00	2					4
70.00	1					5
140.00	2					6
46.66	1		Regulators	1	1	7
25.00	1					8
25.00	1					9
10.00	2		Regulators	2	1	10
50.00	1		Grounding Bank	3	1	11
28.00	1					12
70.00	1		Regulators	5	4	13
70.00	1		Grounding Bank	2	5	14
50.00	2					15
93.33	2					16
50.00	1					17
93.33	2					18
46.66	1					19
93.33	2					20
46.66	1					21
20.00	1		Regulators	7	5	22
22.50	1					23
28.00	1					24
43.00	2					25
47.00	1					26
10.50	1		Regulators	3	1	27
56.00	2					28
53.00	2					29
14.00	1					30
14.00	1		Regulators	2	2	31
2.40	1					32
4.80	2					33
28.00	1					34
93.33	2					35
41.66	1					36
93.33	2					37
10.50	1					38
0.01	1					39
10.50	1					40

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

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.

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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		Distr U	69.00	13.00	7.50
2	LONG LAKE	Distr U	115.00	13.80	
3		Distr U	115.00	13.80	7.90
4	NORTH BROADWAY	Distr U	23.00	4.30	2.50
5	BARNES SUBSTATION	Distr U	23.00	4.30	2.50
6	WOODROW SUBSTATION	Distr U	23.00	4.30	2.50
7	RED RIVER SUBSTATION FARGO	Distr U	110.00	63.50	13.80
8		Distr U	118.00	68.13	13.80
9	CASS COUNTY SUBSTATION FARGO	Distr U	115.00	68.10	13.80
10		Distr U	115.00	24.10	2.40
11	NORDIC SUBSTATION GRAND FORKS	Distr U	115.00	13.80	7.90
12	PARK SUBSTATION EAST GRAND FORKS	Distr U	69.00	4.30	2.50
13	WATER PLANT SUBSTATION EAST GRAND FORKS	Distr U	69.00	13.00	4.30
14	MAYVILLE	Distr U	69.00	13.00	7.50
15		Distr U	69.00	4.30	2.50
16	GATEWAY SUBSTATION GRAND FORKS	Distr U	69.00	13.80	7.90
17		Distr U	69.00	13.80	
18	PORTAL PIPELINE SUBST NEDROSE TWP	Distr U	15.00	4.30	
19		Distr U	15.00	4.30	2.50
20	SOURIS SUBSTATION NEDROSE TWP	Distr U	115.00	13.00	
21		Distr U	115.00	13.80	
22		Distr U	115.00	63.50	13.00
23	HOLLYDALE SUBSTATION PLYMOUTH	Distr U	69.00	14.40	8.30
24	BLUFF CREEK SUBSTATION CHANHASSEN	Distr U	115.00	14.40	8.30
25	EXCELSIOR	Distr U	69.00	13.80	
26		Distr U			
27	DEEPHAVEN SUBSTATION DEEPHAVEN	Distr U	69.00	13.80	
28	GLEASON LAKE SUBSTATION WAYZATA	Distr U	115.00	13.80	7.90
29		Distr U	115.00	14.40	
30		Distr U	115.00	40.70	13.80
31	GLEN LAKE	Distr U	69.00	13.80	7.90
32	SHAKOPEE SUBSTATION SHAKOPEE	Distr U	69.00	13.80	
33		Distr U	15.00	2.40	4.20
34	ORONO SUB[illegible] ORONO	Distr U	69.00	14.40	
35	MOUND SUBSTA[illegible] MOUND	Distr U	69.00	13.80	7.90
36	WATERTOWN	Distr U	69 00	13.80	
37	WINONA SUBSTATION	Distr U	69.00	13.80	
38	GOODVIEW	Distr U	69.00	13.00	7.50
39	LA CRESCENT SUBSTATION LA CRESCENT	Distr U	69.00	13.80	7.90
40	WABASHA SUBSTATION	Distr U	69.00	12.90	4.30

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SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
10.50	1					1
22.40	1		Regulators	5	3	2
28.00	1					3
10.50	2		Regulators	2	1	4
10.25	2		Regulators	15	1	5
12.50	2		Regulators	15	1	6
181.00	2	1				7
46.66	1					8
46.66	1					9
50.00	2					10
93.33	2					11
10.50	1					12
10.50	1					13
6.25	1		Regulators	12	1	14
6.25	1		Capacitor Bank	1	5	15
25.00	1					16
28.00	1					17
5.00	1					18
5.00	1					19
25.00	1					20
25.00	1					21
25.00	1					22
28.00	1					23
46.66	1					24
19.00	1		Regulators	6	2	25
			Capacitor Bank	1	14	26
56.00	2					27
46.66	1					28
47.00	1					29
112.00	1					30
56.00	2		Regulators	6	5	31
56.00	2					32
6.00	3					33
22.40	1					34
56.00	2					35
10.50	1		Regulators	6	1	36
56.00	2		Capacitor Bank	2	37	37
56.00	2		Capacitor Bank	1	7	38
10.50	1					39
2.00	1		Regulators	3	1	40

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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		Distr U	69.00	13.00	7.50
2	BURNSIDE	Distr U	69.00	13.00	7.50
3		Distr U	69.00	13.80	7.50
4	EAST WINONA	Distr U	69.00	13.00	7.50
5		Distr U	69.00	13.80	7.90
6					
7	194 Substations with capacities over 10 MVA				
8	148 Substations with capacities under 10 MVA				
9	Aggregated capacity 540 MVA				
10	Transmission Substations - 5				
11	Distribution Substations - 143				
12	Total 148				
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 Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

SUBSTATIONS (Continued)

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

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11.90	1		Capacitor Bank	1	7	1
7.00	1		Regulators	1	1	2
10.50	1					3
0	1		Regulators	3	1	4
10.50	1					5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

ELECTRIC DISTRIBUTION METERS AND LINE TRANSFORMERS

1. Report below the information called for concerning distribution watt-hour meters and line transformers.

2. Include watt-hour demand distribution meters, but not external demand meters.

3. Show in a footnote the number of distribution watt-hour meters or line transformers held by the respondent under lease from others, jointly owned with others, or held otherwise than by reason of sole ownership by the respondent. If 500 or more meters or line transformers are held under a lease, give name of lessor, date and period of lease, and annual rent. If 500 or more meters or line transformers are held other than by reason of sole ownership or lease, give name of co-owner or other parties, explain basis of accounting for expenses 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.

Line No.	Item (a)	Number of Watt-Hour Meters (b)	LINE TRANSFORMERS	
			Number (c)	Total Capacity (In MVa) (d)
1	Number at Beginning of Year	1,441,306	210,704	12,580
2	Additions During Year			
3	Purchases	84,722	6,778	657
4	Associated with Utility Plant Acquired			
5	TOTAL Additions (Enter Total of lines 3 and 4)	84,722	6,778	657
6	Reductions During Year			
7	Retirements	46,377	3,231	195
8	Associated with Utility Plant Sold			
9	TOTAL Reductions (Enter Total of lines 7 and 8)	46,377	3,231	195
10	Number at End of Year (Lines 1+5-9)	1,479,651	214,251	13,042
11	In Stock	73,213	6,275	698
12	Locked Meters on Customers' Premises	6,884		
13	Inactive Transformers on System			
14	In Customers' Use	1,399,170	207,976	12,344
15	In Company's Use	384		
16	TOTAL End of Year (Enter Total of lines 11 to 15. This line should equal line 10.)	1,479,651	214,251	13,042

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

ENVIRONMENTAL PROTECTION FACILITIES

1. For purposes of this response, environmental protection facilities shall be defined as any building, structure, equipment, facility, or improvement designed and constructed solely for control, reduction, prevention or abatement of discharges or releases into the environment of gaseous, liquid, or solid substances, heat, noise or for the control, reduction, prevention, or abatement of any other adverse impact of an activity on the environment.

2. Report the differences in cost of facilities installed for environmental considerations over the cost of alternative facilities which would otherwise be used without environmental considerations. Use the best engineering design achievable without environmental restrictions as the basis for determining costs without environmental considerations. It is not intended that special design studies be made for purposes of this response. Base the response on the best engineering judgement where direct comparisons are not available.

Include in these differences in costs the costs or estimated costs of environmental protection facilities in service, constructed or modified in connection with the production, transmission, and distribution of electrical energy and shall be reported herein for all such environmental facilities placed in service on or after January 1, 1969, so long as it is readily determinable that such facilities were constructed or modified for environmental rather than operational purposes. Also report similar expenditures for environmental plant included in construction work in progress. Estimate the cost of facilities when the original cost is not available or facilities are jointly owned with another utility, provided the respondent explains the basis of such estimations.

Examples of these costs would include a portion of the costs of tall smokestacks, underground lines, and landscaped substations. Explain such costs in a footnote.

3. In the cost of facilities reported on this page, include an estimated portion of the cost of plant that is or will be used to provide power to operate associated environmental protection facilities. These costs may be estimations on a percentage of plant basis. Explain such estimations in a footnote.

4. Report all costs under the major classifications provided below and include, as a minimum, the items listed hereunder:

A. Air pollution control facilities:
(1) Scrubbers, precipitators, tall smokestacks, etc.
(2) Changes necessary to accommodate use of environmentally clean fuels such as low ash or low sulfur fuels including storage and handling equipment
(3) Monitoring equipment
(4) Other.

B. Water pollution control facilities:
(1) Cooling towers, ponds, piping, pumps, etc.
(2) Waste water treatment equipment
(3) Sanitary waste disposal equipment
(4) Oil interceptors
(5) Sediment control facilities
(6) Monitoring equipment
(7) Other.

C. Solid waste disposal costs:
(1) Ash handling and disposal equipment
(2) Land
(3) Settling ponds
(4) Other.

D. Noise abatement equipment:
(1) Structures
(2) Mufflers
(3) Sound proofing equipment
(4) Monitoring equipment
(5) Other.

E. Esthetic costs:
(1) Architectural costs
(2) Towers
(3) Underground lines
(4) Landscaping
(5) Other.

F. Additional plant capacity necessary due to restricted output from existing facilities, or addition of pollution control facilities.

G. Miscellaneous:
(1) Preparation of environmental reports
(2) Fish and wildlife plants included in Accounts 330, 331, 332, and 335.
(3) Parks and related facilities
(4) Other.

5. In those instances when costs are composites of both actual supportable costs and estimates of costs, specify in column (f) the actual costs that are included in column (e).

6. Report construction work in progress relating to environmental facilities at line 9.

Line No.	Classification of Cost (a)	CHANGES DURING YEAR Additions (b)	Retirements (c)	Adjustments (d)	Balance at End of Year (e)	Actual Cost (f)
1	Air Pollution Control Facilities	$14,551,888		($1,127,511)	$629,063,121	$629,063,121
2	Water Pollution Control Facilities	3,292,590			133,586,792	133,586,792
3	Solid Waste Disposal Costs	24,862			46,640,054	46,640,054
4	Noise Abatement Equipment				7,249,903	7,249,903
5	Esthetic Costs				22,255,402	22,255,402
6	Additional Plant Capacity				84,600,000	84,600,000
7	Miscellaneous (Identify significant)					
8	TOTAL (Total of lines 1 thru 7)	$17,869,340		($1,127,511)	$923,395,272	$923,395,272
9	Construction Work in Progress	(8,218,734)			6,701,617	6,701,617

Name of Respondent Northern States Power Company (Minnesota)	This Report Is: (1) [x] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 1996

ENVIRONMENTAL PROTECTION EXPENSES

1. Show below expenses incurred in connection with the use of environmental protection facilities, the cost of which are reported on page 430. Where it is necessary that allocations and/or estimates of costs be made, state the basis or method used.

2. Include below the costs incurred due to the operation of environmental protection equipment, facilities, and programs.

3. Report expenses under the subheadings listed below.

4. Under item 6 report the difference in cost between environmentally clean fuels and the alternative fuels that would otherwise be used and are available for use.

5. Under item 7 include the cost of replacement power, purchased or generated, to compensate for the deficiency in output from existing plants due to the addition of pollution control equipment, use of alternate environmentally preferable fuels or environmental regulations of governmental bodies. Base the price of replacement power purchased on the average system price of purchased power if the actual cost of such replacement power is not known. Price internally generated replacement power at the system average cost of power generated if the actual cost of specific replacement generation is not known.

6. Under item 8 include ad valorem and other taxes assessed directly on or directly relatable to environmental facilities. Also include under item 8 licensing and similar fees on such facilities.

7. In those instances where expenses are composed of both actual supportable data and estimates of costs, specify in column (c) the actual expenses that are included in column (b).

Line No.	Classification of Expenses (a)	Amount (b)	Actual Expenses (c)
1	Depreciation	$33,684,818	$33,684,818
2	Labor, Maintenance, Materials, and Supplies Cost Related to Env. Facilities and Programs	9,857,646	9,857,646
3	Fuel Related Costs		
4	Operation of Facilities	453,601	453,601
5	Fly Ash and Sulfur Sludge Removal	13,066,396	13,066,396
6	Difference in Cost of Environmentally Clean Fuels		
7	Replacement Power Costs	14,650,410	4,855,244
8	Taxes and Fees	10,209,556	10,209,556
9	Administrative and General	470,339	470,339
10	Other (Identify significant)	* 12,730,770	12,730,770
11	TOTAL	$95,123,536	$85,328,370

< Page 431 Line 10 Column b >

Line #10 includes the following:

Reclamation Costs	$11,570,770
Research & Development	1,160,000
TOTAL	$12,730,770

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